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

Form 10-K

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended **December 31, 2017**

Commission file number **001-08246**

Southwestern Energy Company

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**71-0205415** (I.R.S. Employer Identification No.)
10000 Energy Drive, Spring, Texas (Address of principal executive offices)	**77389** (Zip Code)

(832) 796-1000
(Registrant's telephone number, including area code)

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 $0.01	New York Stock Exchange

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

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 stock held by non-affiliates of the registrant was $3,061,637,340 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2017 of $6.08. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 27, 2018, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 587,063,366

Document Incorporated by Reference

Portions of the registrant's definitive proxy statement to be filed with respect to the annual meeting of stockholders to be held on or about May 22, 2018 are incorporated by reference into Part III of this Form 10-K.

SOUTHWESTERN ENERGY COMPANY
ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2017

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This Annual Report on Form 10-K includes certain statements that may be deemed to be "forward-looking" within the meaning of Section 27A of the Securities Act of 1933, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. We refer you to "Risk Factors" in Item 1A of Part I and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements. The electronic version of this Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those forms filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge as soon as reasonably practicable after they are filed with the Securities and Exchange Commission, or SEC, on our website at www.swn.com. Our corporate governance guidelines and the charters of the Audit, the Compensation, the Health, Safety, Environment and Corporate Responsibility and the Nominating and Governance Committees of our Board of Directors are available on our website, and, upon request, in print free of charge to any stockholder. Information on our website is not incorporated into this report.

We file periodic reports, current reports and proxy statements with the SEC electronically. The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of the SEC's website is www.sec.gov. The public may also read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

ITEM 1. BUSINESS

Southwestern Energy Company (including its subsidiaries, collectively, “we”, “our”, “us”, “the Company” or “Southwestern”) is an independent energy company engaged in exploration, development and production activities, including related natural gas gathering and marketing. Southwestern is a holding company whose assets consist of direct and indirect ownership interests in, and whose business is conducted substantially through, its subsidiaries. Currently we operate exclusively in the United States. Our common stock is listed and traded on the NYSE under the ticker symbol “SWN.”

Southwestern, which was incorporated in Arkansas in 1929 and reincorporated in Delaware in 2006, has its executive offices located at 10000 Energy Drive, Spring, Texas 77389, and can be reached by phone at 832-796-1000. The Company also maintains offices in Conway and Damascus, Arkansas; Tunkhannock, Pennsylvania; and Jane Lew, West Virginia.

Our Business Strategy

We aim to deliver sustainable and assured industry-leading returns through excellence in exploration and production and midstream performance from our extensive resource base and targeted expansion of our activities and assets along the hydrocarbon value chain. Our Company’s formula embodies our corporate philosophy and guides how we operate our business:

$$\frac{R^2}{A} \rightarrow V^{+}$$

Our formula, “The Right People doing the Right Things, wisely investing the cash flow from our underlying Assets will create Value^{+},” also guides our business strategy. We always strive to attract and retain strong talent, to work safely and act ethically with unwavering vigilance for the environment and the communities in which we operate, and to creatively apply technical skills, which we believe will grow long-term value for our shareholders. The arrow in our formula is not a straight line: we acknowledge that factors may adversely affect quarter-by-quarter results, but the path over time points to value creation.

In applying these core principles, we concentrate on:

- ***Financial Strength.*** We are committed to rigorously managing our balance sheet and financial risks. We budget to invest only from our net cash flow (supplemented in 2017 by a portion of proceeds from our equity issuance in 2016 that we previously earmarked for capital investment), protect our projected cash flows through hedging and continue to ensure strong liquidity while de-levering the Company.
- ***Increasing Margins.*** We apply strong technical, operational, commercial and marketing skills to reduce cost, improve the productivity of our wells and pursue commercial arrangements that extract greater value from them. We believe our demonstrated ability to improve margins, especially by levering the scale of our large assets, gives us a competitive advantage as we move into the future.
- ***Exercising Capital Discipline.*** We prepare an economic analysis for our drilling programs and other investments based upon the expected net present value added for each dollar to be invested, which we refer to as Present Value Index, or PVI. We target creating an average of at least a 1.3 PVI in our projects using a 10% discount rate. Our actual PVI results are utilized to help determine the allocation of our future capital investments and are reflected in our management compensation. This disciplined investment approach governs our investment decisions at all times, including the current lower-price commodity market.
- ***Dynamic Management of Assets Throughout Life Cycle.*** We own large-scale, long-life assets in various phases of development. In early stages, we ramp up development through technical, operational and commercial skills, and as they grow we look for ways to maximize their value, through efficient operating practices along with commercial and marketing expertise.
- ***Deepening Our Inventory.*** We continue to expand the inventory of properties that we can develop profitably by converting our extensive resources into proved reserves, targeting additions whose productivity largely has been demonstrated and improving efficiencies in production.

- ***The Hydrocarbon Value Chain.*** We often expand our activities vertically when we believe this will enhance our margins or otherwise provide us competitive advantages. For example, we developed and operate the largest gathering system in the Fayetteville Shale area and currently are investing in a water transportation project in West Virginia. We operate drilling rigs and own a sand mine capable of providing a low cost proppant in hydraulic fracturing. These activities help protect our margin, minimize the risk of unavailability of these resources from third parties, diversify our cash flows and capture additional value.

- ***The Next Chapter of Unconventionals.*** Our company grew dramatically in the 2000s by harnessing and enhancing the newfound combination of hydraulic fracturing and horizontal drilling technologies. Our people constantly search for the next revolutionary technology and other operational advancements to capture greater value in unconventional hydrocarbon resource development. These developments – whether single, step-changing technologies or a combination of several incremental ones – can reduce finding and development costs and thus increase our margins.

- ***Innovative Environmental Solutions and Policy Formation.*** We are a leader in identifying and implementing innovative solutions to unconventional hydrocarbon development to minimize the environmental and community impacts of our activities. We work extensively with governmental, non-governmental and industry stakeholders to develop responsible and cost-effective programs. We demonstrate that a company can operate responsibly *and* profitably, putting us in a better position to comply with new regulations as they evolve.

In early 2016, we faced significant challenges due to a rapid and dramatic fall in natural gas prices, which reduced our revenues and margins. We implemented the first phase of strategic initiatives, which were designed to stabilize the Company financially. We suspended drilling and completion activities, reduced our workforce and revised and extended the maturity of our debt while assuring liquidity to pursue our activities.

When the first phase of these activities was complete, we resumed development activities and entered the next phase, focusing on improving the performance of our large asset portfolio, applying the principles described above. During 2017, we executed on this part of our business strategy by:

- Demonstrating financial discipline by investing within our announced plan of cash flow plus the remaining portion of the proceeds from our 2016 equity offering earmarked for this purpose;
- Investing only in those projects that meet our rigorous economic hurdles at strip pricing;
- Enhancing margins through renegotiation of transportation and processing contracts and expansion of firm pipeline capacity portfolio to maximize realized prices;
- Improving debt maturity schedule through successful $1.15 billion debt issuance, leaving only $92 million in bonds maturing prior to 2022 and no significant other debt maturities expected before December 2020;
- Delivering operational excellence with improved well productivity and economics from enhanced completion techniques, initiation of water infrastructure projects, optimization of surface equipment and managing reservoir drawdown; and
- Significantly expanding our proved reserve quantities across our portfolio through our successful drilling program and improved operational performance as well as improved commodity prices.

In February 2018, we announced the next phase of strategic steps, designed to reposition our portfolio, sharpen our focus on our highest return assets, strengthen our balance sheet and enhance financial performance. These initiatives include:

- Actively pursuing strategic alternatives for the Fayetteville Shale E&P and related Midstream gathering assets;
- Identifying and implementing structural, process and organizational changes to further reduce costs; and
- Utilizing funds realized from the foregoing to reduce debt, supplement Appalachian Basin development capital, potentially return capital to shareholders, and for general corporate purposes.

Our predominant operations, which we refer to as Exploration and Production (“E&P”), are focused on the finding and development of natural gas, oil and natural gas liquid (“NGL”) reserves. We are also focused on creating and capturing additional value through our natural gas gathering and marketing segment, which we refer to as Midstream.

Exploration and Production

Overview

Our primary business is the exploration for and production of natural gas, oil and NGLs, with our current operations solely within the United States and focused on development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. Our operations in northeast Pennsylvania (herein referred to as "Northeast Appalachia") are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale, our operations in West Virginia and southwest Pennsylvania (herein referred to as "Southwest Appalachia") are also focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas, oil and NGL reservoirs, and our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. Collectively, our properties located in Pennsylvania and West Virginia are herein referred to as the "Appalachian Basin." We have smaller holdings in Colorado and Louisiana along with other areas in which we are testing potential new resources. We also have drilling rigs located in Pennsylvania, West Virginia and Arkansas and provide certain oilfield products and services, principally serving our production operations.

- Our E&P segment recorded operating income of $549 million in 2017, compared to an operating loss of $2.4 billion in 2016. The operating loss in 2016 was primarily the result of $2.3 billion of non-cash impairments of natural gas and oil properties due to decreased commodity prices. Excluding the 2016 impairments, our E&P segment operating income increased $632 million in 2017 from 2016 primarily due to a $673 million increase in revenues, partially offset by a $41 million increase in operating expenses due primarily to increased gathering and transportation fees resulting from a shift in our production growth to the Appalachian Basin.

- Cash flow from operations from our E&P segment was $985 million in 2017, compared to $297 million in 2016. Our cash flow from operations increased in 2017 as the effects of higher realized prices and increased production volumes more than offset increased operating expenses.

Oilfield Services Vertical Integration

We provide certain oilfield services that are strategic and economically beneficial for our E&P operations when our E&P activity levels and market pricing support these activities and we can do so more efficiently or cost-effectively. This vertical integration lowers our net well costs, allows us to operate efficiently and helps us to mitigate certain operational environmental risks. Among others, these services have included drilling, hydraulic fracturing, water management and movement, and the mining of sand used as proppant for certain of our well completions.

As of December 31, 2017, we had a total of seven re-entry rigs and two leased pressure pumping spreads with a total capacity of approximately 72,000 horsepower. These services provide us greater flexibility to align our operational activities with commodity prices. In 2017, we provided drilling services for all of our 134 drilled wells and were able to reduce our drilling costs on average by approximately 11%, as compared to recent years. In late 2017, we reinitiated our hydraulic fracturing services and are currently utilizing one pressure pumping spread in Southwest Appalachia. The majority of our wells in 2017 were completed utilizing third-party hydraulic fracturing services who were offering lower costs.

Our Proved Reserves

	For the years ended December 31,		
	2017	2016	2015
Proved reserves *(Bcfe)*	**14,775**	5,253	6,215
Prices used			
Natural gas *(per Mcf)*	**$ 2.98**	$ 2.48	$ 2.59
Oil *(per Bbl)*	**$ 47.79**	$ 39.25	$ 46.79
NGL *(per Bbl)*	**$ 14.41**	$ 6.74	$ 6.82
PV-10:			
Pre-Tax *(in millions)*	**$ 5,784**	$ 1,665	$ 2,417
PV of Taxes *(in millions)*	**(222)**	–	–
After-Tax *(in millions)*	**$ 5,562**	$ 1,665	$ 2,417
Percent of estimated proved reserves that are:			
Natural gas	**75%**	93%	95%
Proved developed	**54%**	99%	93%
Percent of operating revenues generated by natural gas sales	**85%**	89%	93%

Because our proved reserves are primarily natural gas, our reserve estimates and the after-tax PV-10 measure, or standardized measure of discounted future net cash flows relating to proved natural gas, oil and NGL reserve quantities, are highly dependent upon the natural gas price used in our reserve and after-tax PV-10 calculations.

- Our reserves increased in 2017, compared to 2016, primarily through extensions, discoveries and other additions in the Appalachian Basin along with increases in both price and performance revisions across our portfolio.

- The decrease in our reserves in 2016 compared to 2015 was primarily due to downward price revisions, associated with decreased commodity prices, and our production in 2016, partially offset by upward performance revisions in the Appalachian Basin and the Fayetteville Shale.

- The increase in our after-tax PV-10 value in 2017 compared to 2016 was primarily due to higher reserve levels, including a significantly larger percentage of oil and NGL reserves.

- The decrease in our after-tax PV-10 value in 2016 compared to 2015 was primarily due to lower reserve levels.

- We operate approximately 99% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index was approximately 16.5 years at year-end 2017.

The difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2017 Proved Reserves by Category and Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows. Our year-end 2016 and 2015 after-tax PV-10 computations did not have future income taxes because our tax basis in the associated natural gas and oil properties exceeded expected pre-tax cash inflows, and thus do not differ from the pre-tax values.

We believe that the pre-tax PV-10 value of the estimated cash flows related to our estimated proved reserves is a useful supplemental disclosure to the after-tax PV-10 value. Pre-tax PV-10 is based on prices, costs and discount factors that are comparable from company to company, while the after-tax PV-10 is dependent on the unique tax situation of each individual company. We understand that securities analysts use pre-tax PV-10 as one measure of the value of a company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We refer you to "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report for a discussion of our standardized measure of discounted future cash flows related to our proved natural gas, oil and NGL reserves, to the risk factor "Our proved natural gas, oil and NGL reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A of Part I of this Annual Report, and to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

The following table provides an overall and categorical summary of our natural gas, oil and NGL reserves, as of fiscal year-end 2017 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2017, and sets forth 2017 annual information related to production and capital investments for each of our operating areas:

2017 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	Appalachia		Fayetteville		
	Northeast	Southwest	Shale	Other (1)	**Total**
Estimated Proved Reserves:					
Natural Gas *(Bcf)*:					
Developed *(Bcf)*	3,007	833	3,135	4	**6,979**
Undeveloped *(Bcf)*	1,119	2,484	544	–	**4,147**
	4,126	3,317	3,679	4	**11,126**
Crude Oil *(MMBbls)*:					
Developed *(MMBbls)*	–	14.2	–	0.3	**14.5**
Undeveloped *(MMBbls)*	–	51.1	–	–	**51.1**
	–	65.3	–	0.3	**65.6**
Natural Gas Liquids *(MMBbls)*:					
Developed *(MMBbls)*	–	141.9	–	0.3	**142.2**
Undeveloped *(MMBbls)*	–	400.2	–	–	**400.2**
	–	542.1	–	0.3	**542.4**
Total Proved Reserves *(Bcfe)* (2):					
Developed *(Bcfe)*	3,007	1,770	3,135	8	**7,920**
Undeveloped *(Bcfe)*	1,119	5,192	544	–	**6,855**
	4,126	6,962	3,679	8	**14,775**
Percent of Total	28%	47%	25%	0%	**100%**
Percent Proved Developed	73%	25%	85%	100%	**54%**
Percent Proved Undeveloped	27%	75%	15%	0%	**46%**
Production *(Bcfe)*	395	183	316	3	**897**
Capital Investments *(in millions)* (3)	$ 489	$ 547	$ 114	$ 41	**$ 1,191**
Total Gross Producing Wells (4)	983	364	4,191	20	**5,558**
Total Net Producing Wells (4)	516	255	2,921	17	**3,709**
Total Net Acreage	191,226	290,291	917,842	386,304 (5)	**1,785,663**
Net Undeveloped Acreage	87,927	219,709	424,858	369,236 (5)	**1,101,730**
PV-10:					
Pre-Tax *(in millions)* (6)	$ 2,085	$ 1,718	$ 1,978	$ 3	**$ 5,784**
PV of Taxes *(in millions)* (6)	80	66	76	–	**222**
After-Tax *(in millions)* (6)	$ 2,005	$ 1,652	$ 1,902	$ 3	**$ 5,562**
Percent of Total	36%	30%	34%	0%	**100%**
Percent Operated (7)	99%	100%	99%	100%	**99%**

(1) Other consists primarily of properties in Canada, Colorado and Louisiana.

(2) We have no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. We used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

(3) Total and Other capital investments excludes $57 million related to our E&P service companies, of which $37 million related to water infrastructure.

(4) Represents producing wells, including 400 wells in which we only have an overriding royalty interest in Northeast Appalachia, used in the December 31, 2017 reserves calculation.

(5) Excludes exploration licenses for 2,518,519 net acres in New Brunswick, Canada, which have been subject to a moratorium since 2015.

(6) Pre-tax PV-10 (a non-GAAP measure) is one measure of the value of a company's proved reserves that we believe is used by securities analysts to compare relative values among peer companies without regard to income taxes. The reconciling difference in pre-tax PV-10 and the after-tax PV-10, or standardized measure, is the discounted value of future income taxes on the estimated cash flows from our proved natural gas, oil and NGL reserves.

(7) Based upon pre-tax PV-10 of proved developed producing activities.

Lease Expirations

The following table summarizes the leasehold expiring over the next three years, assuming successful wells are not drilled to develop the acreage and leases are not extended:

	For the years ended December 31,		
Net acreage expiring:	2018	2019	2020
Northeast Appalachia	15,731	10,852	4,953
Southwest Appalachia [1]	12,552	14,247	12,456
Fayetteville Shale [2]	262	859	743
Other:			
US – Other Exploration	62,583	104,798	16,212
US – Brown Dense	83,023	5,850	3,196
US – Sand Wash Basin	4,998	4,435	1,000
Canada – New Brunswick [3]	–	–	–

(1) Of this acreage, 2,666 net acres in 2018, 5,907 net acres in 2019 and 1,850 net acres in 2020 can be extended for an average of 5.9 years.

(2) Excludes 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management.

(3) Exploration licenses for 2,518,519 net acres were extended through 2021 but have been subject to a moratorium since 2015.

We refer you to "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report for a more detailed discussion of our proved natural gas, oil and NGL reserves as well as our standardized measure of discounted future net cash flows related to our proved natural gas, oil and NGL reserves. We also refer you to the risk factor "Our proved natural gas, oil and NGL reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A of Part I of this Annual Report and to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

Proved Undeveloped Reserves

Presented below is a summary of changes in our proved undeveloped reserves for 2015, 2016 and 2017:

CHANGES IN PROVED UNDEVELOPED RESERVES

	Appalachia		Fayetteville		
(Bcfe)	Northeast	Southwest	Shale	Other [1]	**Total**
December 31, 2014	**1,598**	**1,481**	**1,716**	**1**	**4,796**
Extensions, discoveries and other additions	138	4	34	–	**176**
Performance and production revisions [2]	513	158	62	–	**733**
Price revisions	(1,447)	(1,413)	(1,357)	–	**(4,217)**
Developed	(488)	(226)	(330)	–	**(1,044)**
Disposition of reserves in place	–	–	–	(1)	**(1)**
Acquisition of reserves in place	–	–	–	–	–
December 31, 2015	**314**	**4**	**125**	**–**	**443**
Extensions, discoveries and other additions	–	–	25	–	**25**
Performance and production revisions [2]	204	–	(1)	–	**203**
Price revisions	(303)	(4)	(67)	–	**(374)**
Developed	(181)	–	(39)	–	**(220)**
Disposition of reserves in place	–	–	–	–	–
Acquisition of reserves in place	–	–	–	–	–
December 31, 2016	**34**	**–**	**43**	**–**	**77**
Extensions, discoveries and other additions [3]	1,100	5,186	543	–	**6,829**
Performance and production revisions [2]	–	6	(14)	–	**(8)**
Price revisions	2	–	1	–	**3**
Developed	(17)	–	(29)	–	**(46)**
Disposition of reserves in place	–	–	–	–	–
Acquisition of reserves in place	–	–	–	–	–
December 31, 2017	**1,119**	**5,192**	**544**	**–**	**6,855**

(1) Other includes properties principally in Colorado and Louisiana along with Ark-La-Tex properties divested in May 2015.

(2) Primarily due to changes associated with the analysis of updated data collected in the year and decreases related to current year production.

(3) The 2017 PUD additions are primarily associated with the increase in commodity prices.

- As of December 31, 2017, we had 6,855 Bcfe of proved undeveloped reserves, all of which we expect will be developed within five years of the initial disclosure as the starting reference date. During 2017, we invested $23 million in connection with converting 46 Bcfe, or 60%, of our proved undeveloped reserves as of December 31, 2016 into proved developed reserves and added 6,829 Bcfe of proved undeveloped reserve additions, primarily in the Appalachian Basin. The significant increase in our proved undeveloped reserve additions in 2017 was the result of adding new undeveloped locations throughout the year through our successful drilling program, improved operational performance and increased commodity pricing across our portfolio.

- As of December 31, 2016, we had 77 Bcfe of proved undeveloped reserves. During 2016, we invested $103 million in connection with converting 220 Bcfe, or 50%, of our proved undeveloped reserves as of December 31, 2015 into proved developed reserves and added 25 Bcfe of proved undeveloped reserve additions in the Fayetteville Shale. As a result of the commodity price environment in 2016, we had downward price revisions of 374 Bcfe which were slightly offset by a 203 Bcfe increase due to performance revisions.

- As of December 31, 2015, we had 443 Bcfe of proved undeveloped reserves. During 2015, we invested $869 million in connection with converting 1,044 Bcfe, or 22%, of our proved undeveloped reserves as of December 31, 2014 into proved developed reserves and added 176 Bcfe of proved undeveloped reserve additions in the Appalachian Basin and the Fayetteville Shale. As a result of the depressed commodity price environment in 2015, we had downward price revisions of 4,217 Bcfe which were slightly offset by a 733 Bcfe increase due to performance revisions.

Our December 31, 2017 proved reserves included 1,375 Bcfe of proved undeveloped reserves from 330 locations that have a positive present value on an undiscounted basis in compliance with proved reserve requirements but do not have a positive present value when discounted at 10%. These properties have a negative present value of $124 million when discounted at 10%. We have made a final investment decision and are committed to developing these reserves within five years from the date of initial booking.

We expect that the development costs for our proved undeveloped reserves of 6,855 Bcfe as of December 31, 2017 will require us to invest an additional $4.2 billion for those reserves to be brought to production. Our ability to make the necessary investments to generate these cash inflows is subject to factors that may be beyond our control. The current commodity price environment has resulted, and could continue to result, in certain reserves no longer being economic to produce, leading to both lower proved reserves and cash flows. We refer you to the risk factors "Natural gas, oil and natural gas liquids prices greatly affect our business, including our revenues, profits, liquidity, growth, ability to repay our debt and the value of our assets" and "Significant capital expenditures are required to replace our reserves and conduct our business" in Item 1A of Part I of this Annual Report and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Reserve Replacement

In recent years, the Appalachian Basin has provided the majority of our reserve additions. In 2017, our proved undeveloped reserves in the Appalachian Basin increased by approximately 6.3 Tcfe, as compared to 2016, primarily due to improved commodity pricing. Our proved developed reserves in the Appalachian Basin increased by approximately 1.2 Tcfe in 2017, as compared to 2016, primarily due to our successful drilling program. Over the past three years, Northeast Appalachia has contributed 790 Bcf, 81 Bcf and 202 Bcf in 2017, 2016 and 2015, respectively, of our reserve additions as a result of successful development activity. Additionally, we added 419 Bcfe, 157 Bcfe and 84 Bcfe of reserves in 2017, 2016 and 2015, respectively, as a result of our drilling program in Southwest Appalachia. We expect our drilling programs in the Appalachian Basin to continue to be the primary source of our reserve additions in the future; however, our ability to add reserves depends upon many factors that are beyond our control. We refer you to the risk factors "Significant capital expenditures are required to replace our reserves and conduct our business" and "If we are not able to replace reserves, we may not be able to grow or sustain production." in Item 1A of Part I of this Annual Report and to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Operations

Northeast Appalachia

Northeast Appalachia represented 44% of our total 2017 net production and 28% of our total reserves as of December 31, 2017. In 2017, our reserves in Northeast Appalachia increased by 2,552 Bcf, which included net additions of 1,890 Bcf, net upward price revisions of 903 Bcf and net upward performance revisions of 154 Bcf, partially offset by production of 395 Bcf. As of December 31, 2017, we had approximately 191,226 net acres in Northeast Appalachia and had spud or acquired 645 operated wells, 538 of which were on production. Below is a summary of Northeast Appalachia's operating results for the latest three years:

	For the years ended December 31,		
	2017	2016	2015
Acreage			
Net undeveloped acres	**87,927** (1)	146,096	174,826
Net developed acres	**103,299**	99,709	95,509
Total net acres	**191,226**	245,805	270,335
Net Production *(Bcf)*	**395**	350	360
Reserves			
Reserves *(Bcf)*	**4,126**	1,574	2,319
Locations:			
Proved developed	**983**	820	767
Proved developed non-producing	**25**	39	23
Proved undeveloped	**100**	2	36
Total locations	**1,108**	861	826
Gross Operated Well Count Summary			
Spud or acquired	**58**	32	177 (2)
Completed	**77**	33	92
Wells to sales	**83**	24	100
Capital Investments *(in millions)*			
Exploratory and development drilling, including workovers	$ **420**	$ 160	$ 472
Acquisition and leasehold	**14**	3	172
Seismic and other	**13**	2	8
Capitalized interest and expense	**42**	39	58
Total capital investments	$ **489**	$ 204	$ 710
Average completed well cost *(in millions)*	$ **5.9**	$ 5.3	$ 5.4
Average lateral length *(feet)*	**6,185**	6,142	5,403

(1) Our undeveloped acreage position as of December 31, 2017 had an average royalty interest of 15%. The decrease in our net undeveloped acres in 2017 as compared to 2016 is due to leasehold expirations in areas we did not plan on developing.

(2) Includes 86 horizontal and 2 vertical acquired wells.

- Our proved undeveloped reserve locations increased significantly in 2017, as compared to 2016, primarily through our successful drilling program in less developed areas and improved realized commodity pricing.

- Our average completed well cost increased in 2017, as compared to 2016, primarily due to tighter hydraulic fracturing spacing and increased activity in delineation areas.

Our ability to bring our Northeast Appalachia production to market depends on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to "Midstream" in Item 1 of Part I of this Annual Report for a discussion of our gathering and transportation arrangements for Northeast Appalachia production.

Southwest Appalachia

Southwest Appalachia represented 20% of our total 2017 net production and 47% of our total reserves as of December 31, 2017. In 2017, our reserves in Southwest Appalachia increased by 6,285 Bcfe, which included net additions of 5,605 Bcfe, net upward price revisions of 738 Bcfe and 125 Bcfe of net upward performance revisions, partially offset by production of 183 Bcfe. As of December 31, 2017, we had approximately 290,291 net acres in Southwest Appalachia and had a total of 360 wells on production that we operated. Below is a summary of Southwest Appalachia's operating results for the latest three years:

	For the years ended December 31,		
	2017	2016	2015
Acreage			
Net undeveloped acres (1)	**219,709** (2)	252,470	193,582
Net developed acres (1)	**70,582**	69,093	231,516
Total net acres	**290,291**	321,563	425,098
Net Production *(Bcfe)*	**183**	148	143
Reserves			
Reserves *(Bcfe)*	**6,962**	677	611
Locations:			
Proved developed	**364**	306 (3)	1,028
Proved developed non-producing	**37**	44 (3)	400
Proved undeveloped	**559**	–	1
Total locations	**960**	350 (3)	1,429
Gross Operated Well Count Summary			
Spud or acquired	**55**	17	48
Completed	**50**	17	38
Wells to sales	**57**	18	47
Capital Investments *(in millions)*			
Exploratory and development drilling, including workovers	$ **353**	$ 111	$ 248
Acquisition and leasehold	**59**	18	409
Seismic and other	**4**	1	2
Capitalized interest and expense	**131**	158	198
Total capital investments	$ **547**	$ 288	$ 857
Average completed well cost *(in millions)* (4)	$ **7.4** (5)	$ 5.4 (5)	$ 6.9
Average lateral length *(feet)* (4)	**7,451** (5)	5,275 (5)	6,985

(1) A divestiture of shallow legacy assets, in which we retained the Marcellus and Utica geologic intervals, resulted in a reclassification of acreage from developed to undeveloped in 2016.

(2) Our undeveloped acreage position as of December 31, 2017 had an average royalty interest of 14%.

(3) Includes the impact of legacy assets divested in 2016.

(4) Includes wells only drilled by SWN.

(5) Excludes one Utica delineation well in 2017 and one in 2016, respectively.

- Our proved undeveloped reserve locations increased significantly in 2017, as compared to 2016, primarily through our successful drilling program in less developed areas and improved realized commodity pricing.

- Our average completed well cost increased in 2017, as compared to 2016, primarily due to longer lateral lengths, tighter hydraulic fracturing spacing and increased proppant volumes.

Our ability to bring our Southwest Appalachia production to market will depend on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to "Midstream" within Item 1 of Part I of this Annual Report for a discussion of our gathering and transportation arrangements for Southwest Appalachia production.

Fayetteville Shale

The Fayetteville Shale represented 35% of our total 2017 net production and 25% of our total reserves as of December 31, 2017. In 2017, our reserves in the Fayetteville Shale increased by 682 Bcf, which included net reserve additions of 591 Bcf, 358 Bcf of net upward revisions due to well performance and net upward price revisions of 49 Bcf, partially offset by production of 316 Bcf. As of December 31, 2017, we held leases for approximately 917,842 net acres in the Fayetteville Shale and had 4,698 wells on production, 4,033 which were operated by us and 665 were outside-operated wells. Below is a summary of the Fayetteville Shale's operating results for the latest three years:

	For the years ended December 31,		
	2017	2016	2015
Acreage			
Net undeveloped acres (1) (2)	**424,858** (3)	426,717	459,312
Net developed acres (1)	**492,984**	491,818	498,329
Total net acres	**917,842**	918,535	957,641
Net Production *(Bcf)*	**316**	375	465
Reserves			
Reserves *(Bcf)*	**3,679**	2,997	3,281
Locations:			
Proved developed	**4,191**	4,217	4,268
Proved developed non-producing	**304**	311	231
Proved undeveloped	**234**	13	61
Total locations	**4,729**	4,541	4,560
Gross Operated Well Count Summary			
Spud or acquired	**6**	4	155
Completed	**23**	34	262
Wells to sales	**25**	43	260
Capital Investments *(in millions)*			
Exploratory and development drilling, including workovers	$ **82**	$ 63	$ 484
Acquisition and leasehold	**1**	2	4
Seismic and other	**9**	–	8
Capitalized interest and expense	**22**	21	69
Total capital investments	$ **114**	$ 86	$ 565
Average completed well cost *(in millions)*	$ **4.2**	$ 3.2	$ 2.8
Average lateral length *(feet)*	**6,609**	5,717	5,729

(1) A divestiture of shallow legacy Arkoma assets in 2015, in which we retained the geologic interval from the top of the upper Fayetteville Formation down to the base of the Chattanooga Formation, resulted in a reclassification of acreage from developed to undeveloped.

(2) Includes 226,312, 227,656 and 202,156 net undeveloped acres in the Arkoma Basin as of December 31, 2017, 2016 and 2015, respectively.

(3) Our undeveloped acreage position as of December 31, 2017 had an average royalty interest of 13%.

- Our proved undeveloped reserve locations increased significantly in 2017, as compared to 2016, primarily due to improved realized commodity pricing.

- Our average completed well cost increased in 2017, as compared to 2016, primarily due to longer lateral lengths and increased activity in the deeper Moorefield zone.

Of the acreage we hold in the Fayetteville Shale, the Ozark Highlands Unit accounts for 158,231 acres and lies entirely within the Ozark National Forest. Following the commencement of two court actions, which were subsequently consolidated, alleging deficiencies in the Environmental Impact Statement issued in connection with the grant of the leases by the Bureau of Land Management (BLM) in the Ozark National Forest, the BLM discontinued approval of operational permits in the forest, including permits to drill, pending resolution of the litigation. Although the case was dismissed in May 2017, the BLM is not issuing drilling permits. If and when permit issuance resumes, the leases will expire unless, within nine months, we commence drilling or resume rental payments. At year-end 2017, after excluding our acreage in the conventional Arkoma Basin and the federal acreage we hold in the Ozark Highlands Unit, approximately 99% of our 533,299 total net leasehold acres remaining in the Fayetteville Shale was held by production. For more information about our acreage and well count, we refer you to "Properties" in Item 2 of Part I of this Annual Report. We also refer you to the risk factor "Certain of our undeveloped assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage" in Item 1A of Part I of this Annual Report.

In February 2018, we announced an initiative to actively pursue strategic alternatives for the Fayetteville Shale E&P and related Midstream gathering assets.

Other

Excluding 2,518,519 acres in New Brunswick, Canada, which have been subject to a moratorium since 2015, we held 369,236 net undeveloped acres for the potential development of new resources as of December 31, 2017. This compares to 492,389 net undeveloped acres held at year-end 2016 and 1,142,856 net undeveloped acres held at year-end 2015, excluding the New Brunswick acreage.

We limited our activities in areas beyond our assets in the Appalachian Basin and the Fayetteville Shale during 2017, 2016 and 2015 as a result of the commodity price environment as we focused on these more proven development plays. There can be no assurance that any prospects outside of our development plays will result in viable projects or that we will not abandon our initial investments.

New Brunswick, Canada. In March 2010, we successfully bid for exclusive licenses from the Department of Natural Resources of New Brunswick to search and conduct an exploration program covering 2,518,519 net acres in the province in order to test new hydrocarbon basins. In 2015, the provincial government in New Brunswick imposed a moratorium on hydraulic fracturing until it is satisfied with a list of conditions. In response to this moratorium, the Company requested and was granted an extension of its licenses to March 2021. In May 2016, the provincial government announced that the moratorium would continue indefinitely. Unless and until the moratorium is lifted, we will not be able to develop these assets. Given this development, we recognized an impairment of $39 million, net of tax, associated with our investment in New Brunswick in the second quarter of 2016.

Acquisitions and Divestitures

In September 2016, we sold approximately 55,000 net acres in West Virginia for approximately $401 million. As of December 2015, these assets included approximately 11 Bcfe of proved reserves.

In May 2015, we sold conventional oil and gas assets located in East Texas and the Arkoma Basin for approximately $211 million. As of December 2014, these assets included approximately 184 Bcf of proved reserves.

In April 2015, we sold our gathering assets located in Bradford and Lycoming counties in northeast Pennsylvania for approximately $489 million. The assets included approximately 100 miles of natural gas gathering pipelines with nearly 600 million cubic feet per day of capacity.

In January 2015, we acquired approximately 46,700 net acres in northeast Pennsylvania for $270 million. As part of this transaction, we also received firm transportation capacity of 260 million cubic feet per day predominately on the Millennium pipeline.

In December 2014, we acquired approximately 413,000 net acres in West Virginia and southwest Pennsylvania with plans to target the Marcellus, Utica and Upper Devonian Shales for approximately $5.0 billion. Additionally, in January 2015, we acquired an additional approximate 30,000 net acres in this area for $357 million.

Capital Investments

(in millions)	For the years ended December 31, 2017	2016	2015
E&P Capital Investments by Type			
Exploratory and development drilling, including workovers	$ **878**	$ 358	$ 1,226
Acquisition and leasehold	**86**	23	607
Seismic expenditures	**7**	1	6
Drilling rigs, sand facility, water infrastructure and other	**65**	2	40
Capitalized interest and other expenses	**212**	239	379
Total E&P capital investments	$ **1,248**	$ 623	$ 2,258
E&P Capital Investments by Area			
Northeast Appalachia	$ **489**	$ 204	$ 710
Southwest Appalachia	**547**	288	857
Fayetteville Shale	**114**	86	565
Other	**98**	45	126
Total E&P capital investments	$ **1,248**	$ 623	$ 2,258

- The significant increase in 2017 E&P capital investing, as compared to 2016, resulted from the resumption of activity following our decision to suspend drilling activity in the first half of 2016 due to an unfavorable commodity price environment. We began increasing activity in the second half of 2016 as forward pricing improved.

- The significant decrease in 2016 E&P capital investing, as compared to 2015, was the result of suspending drilling activity in the first half of 2016 due to an unfavorable commodity price environment.

- In 2017, we drilled 134 wells (120 of which were spud in 2017), completed 151 wells, placed 166 wells to sales and had 92 wells in progress at year-end.

- Of the 92 wells in progress at year-end, 52 and 40 were located in Northeast Appalachia and Southwest Appalachia, respectively, and 19 of these wells were waiting on pipeline or production facilities.

We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Investments" within Item 7 of Part II of this Annual Report for additional discussion of the factors that could impact our planned capital investments in 2018.

Sales, Delivery Commitments and Customers

Sales. The following tables present historical information about our production volumes for natural gas, oil and NGLs and our average realized natural gas, oil and NGL sales prices:

	For the years ended December 31, 2017	2016	2015
Average net daily production *(MMcfe/day)*	**2,456**	2,391	2,675
Production:			
Natural gas *(Bcf)*	**797**	788	899
Oil *(MBbls)*	**2,327**	2,192	2,265
NGLs *(MBbls)*	**14,245**	12,372	10,702
Total production *(Bcfe)*	**897**	875	976

- The increase in production in 2017 resulted primarily from a 45 Bcf increase in net production from our Northeast Appalachia properties and a 35 Bcfe increase in net production from our Southwest Appalachia properties, partially offset by a decrease of 59 Bcf from our Fayetteville Shale properties.

- The decrease in production in 2016 resulted primarily from normal declines in production from existing wells that were not fully offset by production from new wells, given our reduced drilling activities. In particular, we experienced a 90 Bcf decrease in net production from our Fayetteville Shale properties, a 10 Bcf decrease in net production from our Northeast Appalachia properties and a 6 Bcfe decrease in other properties, which was partially offset by a 5 Bcfe increase in net production from our Southwest Appalachia properties.

Average realized price per unit:	For the years ended December 31, 2017	2016	2015
Natural gas sales, excluding derivatives *(per Mcf)*	**$ 2.23**	$ 1.59	$ 1.91
Effect of settled gain (loss) on derivatives *(per Mcf)*	**(0.04)**	0.05	0.46
Natural gas sales, including derivatives *(per Mcf)*	**$ 2.19**	$ 1.64	$ 2.37
Oil sales *(per Bbl)*	**$ 43.12**	$ 31.20	$ 33.25
NGL sales, excluding derivatives *(per Bbl)*	**$ 14.46**	$ 7.46	$ 6.80
Effect of settled gain (loss) on derivatives *(per Bbl)*	**0.02**	–	–
NGL sales, including derivatives *(per Bbl)*	**$ 14.48**	$ 7.46	$ 6.80

Sales of natural gas, oil and NGL production are conducted under contracts that reflect current prices and are subject to seasonal price swings. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand for our production. We regularly enter into various derivative and other financial arrangements with respect to a portion of our projected production to support certain desired levels of cash flow and to minimize the impact of price fluctuations. Our policies prohibit speculation with derivatives and limit agreements to counterparties with appropriate credit standings.

As of December 31, 2017, we had the following commodity price derivatives in place on our targeted future production:

Financial protection on production as of December 31, 2017:	For the years ended December 31, 2018	2019	2020
Natural gas *(Bcf)*	489	201	–
Ethane *(MBbls)*	183	–	–
Propane *(MBbls)*	183	–	–

As of February 27, 2018, we had the following commodity price derivatives in place on our targeted future production:

Financial protection on production as of February 27, 2018:	For the years ended December 31, 2018	2019	2020
Natural gas *(Bcf)*	566	216	–
Ethane *(MBbls)*	183	–	–
Propane *(MBbls)*	1,353	–	–

We intend to financially protect pricing on a large portion of expected future production volumes designed to assure certain desired levels of cash flow. We refer you to Item 7A of Part II of this Annual Report, "Quantitative and Qualitative Disclosures about Market Risks," for further information regarding our derivatives and risk management as of December 31, 2017.

During 2017, the average price we received for our natural gas production, excluding the impact of derivatives, was approximately $0.88 per Mcf lower than average New York Mercantile Exchange, or NYMEX, prices. Differences between NYMEX and price realized are due primarily to locational differences and transportation cost.

As of December 31, 2017, we have partially mitigated the volatility of basis differentials by protecting basis on approximately 182 Bcf and 70 Bcf of our 2018 and 2019 expected natural gas production, respectively, through physical sales arrangements at a basis differential to NYMEX natural gas price of approximately ($0.25) per MMBtu and ($0.31) per MMBtu for 2018 and 2019, respectively.

We have also financially protected basis on approximately 44 Bcf and less than 1 Bcf of our 2018 and 2019 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately ($0.48) per MMBtu and ($0.59) per MMBtu for 2018 and 2019, respectively, as of December 31, 2017.

We refer you to Note 4 to our consolidated financial statements for additional discussion about our derivatives and risk management activities.

Delivery Commitments. As of December 31, 2017, we had natural gas delivery commitments of 408 Bcf in 2018 and 100 Bcf in 2019 under existing agreements. These amounts are well below our expected 2018 natural gas production from Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale and expected 2019 production from our available reserves, which are not subject to any priorities or curtailments that may affect quantities delivered to our customers or any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond our control that may affect our ability to meet our contractual obligations other than those discussed in Item 1A "Risk Factors" of Part I of this Annual Report. We expect to be able to fulfill all of our short-term and long-term contractual obligations to provide natural gas from our own production of available reserves; however, if we are unable to do so, we may have to purchase natural gas at market to fulfill our obligations.

Customers. Our E&P production is marketed primarily by our Midstream segment. Our customers include major energy companies, utilities and industrial purchasers of natural gas. For the year ended December 31, 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.3% of total natural gas, oil and NGL sales. During the years ended December 31, 2016 and 2015, no single third-party purchaser accounted for 10% or more of our consolidated revenues. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production.

Competition

All phases of the natural gas and oil industry are highly competitive. We compete in the acquisition and disposition of properties, the search for and development of reserves, the production and sale of natural gas and oil, its gathering and transportation (whether we are shipping or operate the transmission facilities) and the securing of labor and equipment required to conduct our operations. Our competitors include major oil and natural gas companies, other independent oil and natural gas companies, individual producers and operators and developers of gathering and transportation systems. Many of these competitors have financial and other resources that substantially exceed those available to us. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. We also face competition in accessing pipeline and other services to transport our product to market, particularly in the northeastern United States, where potential production levels exceed currently available capacity. Likewise, there are substitutes for the commodities we produce, such as other fuels for power generation, heating and transportation, and those markets in effect compete with us.

We cannot predict whether and to what extent any market reforms initiated by the Federal Energy Regulatory Commission, or the FERC, or any new energy legislation or regulations will achieve the goal of increasing competition, lessening preferential treatment and enhancing transparency in markets in which our natural gas production is sold. Similarly, we cannot predict whether legal constraints that have hindered the development of new transportation infrastructure, particularly in the northeastern United States, will continue. However, we do not believe that we will be disproportionately affected as compared to other natural gas and oil producers and marketers by any action taken by the FERC or any other legislative or regulatory body or the status of the development of transportation facilities.

Regulation

Producing natural gas and oil resources and transporting and selling production historically have been heavily regulated. For example, state governments regulate the location of wells and establish the minimum size for spacing units. Permits typically are required before drilling. State and local government zoning and land use regulations may also limit the locations for drilling and production. Similar regulations can also affect the location, construction and operation of gathering and other pipelines needed to transport production to market. In addition, various suppliers of goods and services may require licensing.

Currently in the United States, the price at which natural gas, oil or NGLs may be sold is not regulated. Congress has imposed price regulation from time to time, and there can be no assurance that the current, less stringent regulatory approach will continue. In December 2015, the federal government repealed a 40-year ban on the export of crude oil. The export of natural gas continues to require federal permits. Broader freedom to export could lead to higher prices. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") and the rules that the U.S. Commodity Futures Trading Commission, or the CFTC, the SEC, and certain other regulators have issued thereunder regulate certain swaps, futures and options contracts in the major energy markets, including for natural gas, oil and NGLs.

Producing and transporting natural gas and oil is also subject to extensive environmental regulation. We refer you to "Other — Environmental Regulation" in Item 1 of Part 1 of this Annual Report and the risk factor "We are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities" in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

Midstream

Through our affiliated midstream subsidiaries, we engage in marketing and natural gas gathering activities which primarily support our E&P operations. We generate revenue from gathering fees associated with the transportation of natural gas to market and through the marketing of natural gas, oil and NGLs. Our Midstream segment complements our E&P initiatives and, in some areas, competes with other midstream providers for unaffiliated business.

	For the years ended December 31,		
	2017	2016	2015
Marketing revenues *(in millions)*	**$ 2,867**	$ 2,191	$ 2,628
Gathering revenues *(in millions)*	**331**	378	491 (1)
Total operating revenues *(in millions)*	**3,198**	2,569	3,119
Operating income *(in millions)*	**183**	209	583 (2)
Cash flows from operations *(in millions)*	**$ 208**	$ 222	$ 540
Capital investments – gathering *(in millions)*	**32**	21	58
Natural gas gathered from the Fayetteville Shale *(Bcf)*			
Operated wells *(Bcf)*	**463**	558	695
Third-party operated wells *(Bcf)*	**35**	42	55
Total volumes gathered in the Fayetteville Shale *(Bcf)*	**498**	600	750
Volumes marketed *(Bcfe)*	**1,067**	1,062	1,127
Percent natural gas marketed from affiliated E&P operations	**96%**	93%	97%
Percent oil and NGLs marketed from affiliated E&P operations	**63%**	65%	60%

(1) During 2015, we divested our gathering assets in northeast Pennsylvania and East Texas. The divested gathering assets accounted for $21 million of our gathering revenues for the year ended December 31, 2015.

(2) Operating income in 2015 includes a $277 million net gain related to the sale of our northeast Pennsylvania and East Texas gathering assets.

- Operating income from our Midstream segment decreased $26 million in 2017 compared to 2016, primarily due to a $47 million decrease in gas gathering revenues related to a decrease in Fayetteville Shale gathered volumes, and a $3 million decrease in marketing margin, partially offset by a $18 million decrease in operating costs and expenses, primarily related to decreased compression rental and maintenance activities, and a $6 million gain on sale of certain compressor equipment.

- Excluding the $277 million gain on the 2015 sale of our northeast Pennsylvania and East Texas gathering assets, operating income decreased $97 million in 2016 compared to 2015, primarily due to a 20% decrease in volumes gathered, resulting from lower production volumes in the Fayetteville Shale.

- Revenues increased in 2017, compared to 2016, as the effect of an increase in the price received for volumes marketed was only partially offset by a decrease in volumes gathered.

- Revenues decreased in 2016, compared to 2015, primarily due to a decrease in the price received for volumes marketed, a decrease in volumes marketed and a decrease in volumes gathered.

- Cash flow from operations generated by our Midstream segment decreased in 2017, compared to 2016, primarily due to a $26 million decrease operating income, partially offset by a $12 million increase primarily related to timing differences of payables and receivables between the respective periods.

- The decrease in cash flow from operations in 2016, compared to 2015, was primarily due to decreased revenues and a decrease related to timing differences of payables and receivables between the respective periods, partially offset by a decrease in operating costs and expenses.

Gas Gathering

Since the sale of our gathering assets in northeast Pennsylvania and Texas in 2015, our gathering assets are concentrated in the Fayetteville Shale in Arkansas. At the end of 2017, we had approximately 2,045 miles of pipe from the individual wellheads to the transmission lines and compression equipment representing in aggregate approximately 377,070 horsepower that had been installed at 58 central point gathering facilities in the Fayetteville Shale. In February 2018, we announced an initiative to actively pursue strategic alternatives for the Fayetteville Shale E&P and related Midstream gathering assets.

Marketing

We attempt to capture opportunities related to the marketing and transportation of natural gas, oil and NGLs primarily involving the marketing of our own equity production and that of royalty owners in our wells. Additionally, we manage portfolio and basis risk, acquire transportation rights on third-party pipelines and in limited circumstances, purchase third-party natural gas to fulfill commitments specific to a geographic location.

Northeast Appalachia. Our transportation portfolio in Northeast Appalachia is highly-diversified and structured to capture improving northeast basis differentials, which we expect to enhance our margins in 2018, and allows us to access premium city-gate markets as well as deliveries across the greater Appalachia area down to the southeast United States. The capacity agreements contain multiple extension and reduction options that allow us to right-size our transportation portfolio as needed for our production or to capture future market opportunities. The table below details our firm transportation, firm sales and total takeaway capacity over the next three years as of February 27, 2018:

	For the year ended December 31,		
(MMBtu/d)	2018	2019	2020
Firm transportation	1,307,000	1,376,000	1,363,000
Firm sales	143,000	73,000	35,000
Total firm takeaway – Northeast Appalachia	1,450,000	1,449,000	1,398,000

Southwest Appalachia. Our transportation portfolio for all products in Southwest Appalachia allows us to capitalize on strengthening markets and provides a path for production growth. Over the next four years, agreements with ET Rover Pipeline LLC and Columbia Pipeline Group, Inc.'s Mountaineer Xpress and Gulf Xpress pipelines will allow us to access high-demand markets along the Gulf Coast while also capturing materially improving in-basin pricing. In addition to our natural gas transportation, we have ethane take-away capacity that provides direct exposure to Mont Belvieu pricing. New ethane cracker demand and export capacity is expected to further strengthen ethane pricing. The table below details our firm transportation, firm sales and total takeaway capacity over the next three years as of February 27, 2018:

	For the year ended December 31,		
(MMBtu/d)	2018	2019	2020
Firm transportation	327,000	777,000	777,000
Firm sales	101,000	55,000	92,000
Total firm takeaway – Southwest Appalachia	428,000	832,000	869,000

Fayetteville Shale. Our transportation portfolio in the Fayetteville Shale allows our production to be sold in markets located from central Arkansas to highly sought after Gulf Coast markets. In 2017, we took steps to right-size this capacity by restructuring our transportation agreements with Texas Gas Transmission, LLC. The new agreements were approved by the FERC and, effective November 1, 2017, reduced our Fayetteville Lateral volume commitment from 800,000 MMBtu per day to 100,000 MMBtu per day from November 2017 to October 2020 at existing rates, restructured firm transportation agreements and demand fees beginning in 2021 on 550,000 MMBtu per day of contracted volumes, reducing annually through 2030, at a rate of approximately $0.10 per MMBtu. Additionally the agreements provided for firm transportation of all volumes between the contracted firm amount up to 800,000 MMBtu per day each year starting in 2021. This amendment of our agreements provides fixed rate, guaranteed long-term takeaway capacity for our Fayetteville production. A competitor of Texas Gas Transmission has sought review of the FERC's order, and although we cannot predict with certainty the outcome, we do not expect the order to be overturned. The table below details our firm transportation, firm sales and total takeaway capacity over the next three years as of February 27, 2018:

	For the year ended December 31,		
(MMBtu/d)	2018	2019	2020
Firm transportation	1,300,000	1,300,000	1,283,333
Firm sales	–	–	–
Total firm takeaway – Fayetteville Shale	1,300,000	1,300,000	1,283,333

Demand Charges

As of December 31, 2017, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $9.2 billion, $3.0 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. We also have guarantee obligations of up to $832 million of that amount.

We refer you to Note 8, "Commitments and Contingencies" in the consolidated financial statements for further details on our demand charges and the risk factor "We have made significant investments in pipelines and gathering systems and contracts and in oilfield service businesses, including our drilling rigs, pressure pumping equipment and sand mine operations, to lower costs and secure inputs for our operations and transportation for our production. If our exploration and production activities are curtailed or disrupted, we may not recover our investment in these activities, which could adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers" in Item 1A of Part I of this Annual Report.

Competition

Our marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than we have. Some of these competitors are other producers and affiliates of companies with extensive pipeline systems that are used for transportation from producers to end users. Other factors affecting competition are the cost and availability of alternative fuels, the level of consumer demand and the cost of and proximity to pipelines and other transportation facilities. We believe that our ability to compete effectively within the marketing segment in the future depends upon establishing and maintaining strong relationships with producers and end-users.

Customers

Our marketing customers include major energy companies, utilities and industrial purchasers of natural gas. For the year ended December 31, 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.3% of total natural gas, oil and NGL sales. During the years ended December 31, 2016 and 2015, no single third-party purchaser accounted for 10% or more of our consolidated revenues. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production.

Regulation

The transportation of natural gas, oil and NGLs is heavily regulated. Interstate pipelines must obtain authorization from the FERC to operate in interstate commerce, and state governments typically must authorize the construction of pipelines for intrastate service. The FERC currently allows interstate pipelines to adopt market-based rates; however, in the past the FERC has regulated pipeline tariffs and could do so again in the future. State tariff regulations vary. Currently, all pipelines we own are intrastate.

State and local permitting, zoning and land use regulations can affect the location, construction and operation of gathering and other pipelines needed to transport production to market, and the lack of new pipeline capacity can limit our ability to reach relevant markets for the sale of the commodities we produce. In addition, various suppliers of goods and services to our midstream business may require licensing.

The transportation of natural gas and oil is also subject to extensive environmental regulation. We refer you to "Other – Environmental Regulation" in Item 1 of Part I of this Annual Report and the risk factor "We are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities" in Item 1A of Part I of this Annual Report for a discussion of the impact of environmental regulation on our business.

Other

Our other operations have historically consisted of limited real estate development activities and a natural gas vehicles ("NGV") fueling station in Damascus, Arkansas, which was sold in May 2016. We currently have no significant business activity outside of our E&P and Midstream segments.

Environmental Regulation

General. Our operations are subject to environmental regulation in the jurisdictions in which we operate. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements to drill or operate wells and also regulate the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the prevention and cleanup of pollutants and other matters. We maintain insurance for costs of clean-up operations in limited instances arising out of sudden and accidental events, but otherwise we are not fully insured against all such risks. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Certain laws and legal principles can make us liable for environmental damage to property we have sold, and although we generally require purchasers to assume that liability, there is no assurance that they will have sufficient funds should a liability arise. Changes in environmental laws and regulations occur frequently, and any changes may result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements. We do not expect continued compliance with existing requirements to have a material adverse impact on us, but there can be no assurance that this will continue in the future.

The following is a summary of the more significant existing environmental and worker health and safety laws and regulations to which we are subject.

Certain U.S. Statutes. CERCLA, also known as the "Superfund law," imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act, as amended, or RCRA, generally does not regulate wastes generated by the exploration and production of natural gas and oil. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil, natural gas or geothermal energy." However, legislative and regulatory initiatives have been considered from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such measures were to be enacted, it could have a significant impact on our operating costs. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Clean Water Act, as amended, or CWA, and analogous state laws, impose restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into regulated waters. Permits must be obtained to discharge pollutants to regulated waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. The EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

The Oil Pollution Act, as amended, or OPA, and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in regulated waters. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. Although liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. In 2017 oil accounted for 2% of our total production, compared to 2% of our total production for 2016 and less than 1% of our total production for 2015, although we expect this percentage to increase as we continue to develop our Southwest Appalachia assets.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration for and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed on them may be subject to CERCLA, the Clean

Water Act, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

The Clean Air Act, as amended, restricts emissions into the atmosphere. Various activities in our operations, such as drilling, pumping and the use of vehicles, can release matter subject to regulation. We must obtain permits, typically from local authorities, to conduct various activities. Federal and state governmental agencies are looking into the issues associated with methane and other emissions from oil and natural gas activities, and further regulation could increase our costs or restrict our ability to produce. Although methane emissions are not currently regulated at the federal level, we are required to report emissions of various greenhouse gases, including methane.

The Endangered Species Act and comparable state laws protect species threatened with possible extinction. Protection of threatened and endangered species may have the effect of prohibiting or delaying us from obtaining drilling and other permits and may include restrictions on road building and other activities in areas containing the affected species or their habitats. Based on the species that have been identified to date, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our operations at this time.

Hydraulic Fracturing. We utilize hydraulic fracturing in drilling wells as a means of maximizing their productivity. It is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas, and associated liquids from dense and deep rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore.

In the past few years, there has been an increased focus on environmental aspects of hydraulic fracturing practice, both in the United States and abroad. In the United States, hydraulic fracturing is typically regulated by state oil and natural gas commissions, but federal agencies have started to assert regulatory authority over certain aspects of the process. For example, the Environmental Protection Agency, or EPA, issued final rules effective as of October 15, 2012 that subject oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS programs. In May 2016, the EPA finalized additional regulations to control methane and volatile organic compound emissions from certain oil and gas equipment and operations. The EPA also finalized pretreatment standards that would prohibit the indirect discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned treatment works. Based on our current operations and practices, management believes such newly promulgated rules will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management’s view may change in the future.

In addition, there are certain governmental reviews either underway or proposed that focus on environmental aspects of hydraulic fracturing practices. A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, in December 2016, the EPA released its final report regarding the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances such as water withdrawals for fracturing in times or areas of low water availability, surface spills during the management of fracturing fluids, chemicals or produced water, injection of fracturing fluids into wells with inadequate mechanical integrity, injection of fracturing fluids directly into groundwater resources, discharge of inadequately treated fracturing wastewater to surface waters and disposal or storage of fracturing wastewater in unlined pits. The results of these studies could lead federal and state governments and agencies to develop and implement additional regulations.

Although the current federal administration has relaxed many regulations adopted in the latter part of the prior administration, some states in which we operate have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

Increased regulation and attention given to the hydraulic fracturing process has led to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas, and associated liquids including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. We refer you to the risk factor "We are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities" in Item 1A of Part I of this Annual Report.

In addition, concerns have been raised about the potential for seismic activity to occur from the use of underground injection control wells, a predominant method for disposing of waste water from oil and gas activities. We operate injection wells and utilize injection wells owned by third parties to dispose of waste water associated with our operations, subject to regulatory restrictions relating to seismicity. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others.

Greenhouse Gas Emissions. In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their greenhouse gas emissions also will be required to meet "best available control technology" standards that will be established on a case-by case basis. One of our subsidiaries operates compressor stations, which are facilities that are required to adhere to the PSD or Title V permit requirements. EPA rulemakings related to greenhouse gas emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

The EPA also has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. Although Congress from time to time has considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of states, including states in which we operate, have enacted or passed measures to track and reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.

The adoption and implementation of regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or install new equipment to reduce emissions of greenhouse gases associated with our operations. In addition, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. At the same time, new laws and regulations are prompting power producers to shift from coal to natural gas, which is increasing demand.

Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions (the "Paris Agreement"). The Paris Agreement entered into effect in November 2016 after more than 70 nations, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. In June 2017, President Trump announced that the United States intends to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or a separate agreement. In August 2017, the U.S. Department of State officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time. To the extent that the United States and other countries implement this agreement or impose other climate change regulations on the oil and gas industry, it could have an adverse effect on our business.

Employee health and safety. Our operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

Canada. Our activities in Canada have, to date, been limited to certain geological and geophysical activities and now are subject to a moratorium. If and when the moratorium ends and should we begin drilling and development activities in New Brunswick, we will be subject to federal, provincial and local environmental regulations.

Employees

As of December 31, 2017, we had 1,575 total employees. None of our employees were covered by a collective bargaining agreement at year-end 2017. We believe that our relationships with our employees are good.

Executive Officers of the Registrant

The following table shows certain information as of February 27, 2018 about our executive officers, as defined in Rule 3b-7 of the Securities Exchange Act of 1934:

Name	**Age**	**Officer Position**
William J. Way	58	President and Chief Executive Officer
Clayton A. Carrell	52	Executive Vice President and Chief Operating Officer
J. David Cecil	51	Executive Vice President Corporate Development
Jennifer E. Stewart	54	Senior Vice President and Chief Financial Officer – Interim
Jennifer N. McCauley	54	Senior Vice President – Administration
John C. Ale	63	Senior Vice President, General Counsel and Secretary
Jason Kurtz	47	Vice President – Marketing and Transportation

Mr. Way was appointed Chief Executive Officer in January 2016. Prior to that, he served as Chief Operating Officer since 2011, having also been appointed President in December 2014. Prior to joining the Company, he was Senior Vice President, Americas of BG Group plc with responsibility for E&P, Midstream and LNG operations in the United States, Trinidad and Tobago, Chile, Bolivia, Canada and Argentina since 2007.

Mr. Carrell was appointed Executive Vice President and Chief Operating Officer in December 2017. Prior to joining the Company, he was Executive Vice President and Chief Operating Officer of EP Energy since 2012.

Mr. Cecil was appointed Executive Vice President Corporate Development in August 2017. Prior to joining the Company, he was Managing Director and Head of the North American E&P group of Lazard since 2012.

Ms. Stewart was appointed Senior Vice President and Chief Financial Officer – Interim in June 2017. Prior to serving as the Chief Financial Officer – Interim, she was Senior Vice President, Tax and Treasury. Ms. Stewart joined the Company in 2010 as Vice President, Tax.

Ms. McCauley was appointed Senior Vice President – Administration in April 2016. Prior to that, she served as Senior Vice President – Human Resources since 2009.

Mr. Ale was appointed Senior Vice President, General Counsel and Secretary in November 2013. Prior to that, he was Vice President and General Counsel of Occidental Petroleum Corporation since April 2012. Prior to that, he was a partner with Skadden, Arps, Slate, Meagher & Flom LLP since 2002.

Mr. Kurtz was appointed Vice President of Marketing and Transportation in May 2011. Prior to that, he served in various marketing roles since joining the Company in May 1997.

There are no family relationships between any of the Company's directors or executive officers.

GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below apply to the indicated terms as used in this Annual Report. All natural gas reserves reported in this Annual Report are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit. All currency amounts are in U.S. dollars unless specified otherwise.

"Acquisition of properties" Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties. For additional information, see the SEC's definition in Rule 4-10(a) (1) of Regulation S-X, a link for which is available at the SEC's website.

"Available reserves" Estimates of the amounts of natural gas, oil and NGLs which the registrant can produce from current proved developed reserves using presently installed equipment under existing economic and operating conditions and an estimate of amounts that others can deliver to the registrant under long-term contracts or agreements on a per-day, per-month, or per-year basis. For additional information, see the SEC's definition in Item 1207(d) of Regulation S-K, a link for which is available at the SEC's website.

"Basis differential" The difference in price for a commodity between a market index price and the price at a specified location.

"Bbl" One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"Bcf" One billion cubic feet of natural gas.

"Bcfe" One billion cubic feet of natural gas equivalent. Determined using the ratio of one barrel of oil or natural gas liquids to six Mcf of natural gas.

"Btu" One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"Deterministic estimate" The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure. For additional information, see the SEC's definition in Rule 4-10(a) (5) of Regulation S-X, a link for which is available at the SEC's website.

"Developed oil and gas reserves" Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For additional information, see the SEC's definition in Rule 4-10(a) (6) of Regulation S-X, a link for which is available at the SEC's website.

"Development costs" Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing natural gas, oil and NGLs. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

For additional information, see the SEC's definition in Rule 4-10(a) (7) of Regulation S-X, a link for which is available at the SEC's website.

"Development project" A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project. For additional information, see the SEC’s definition in Rule 4-10(a) (8) of Regulation S-X, a link for which is available at the SEC’s website.

“Development well” A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. For additional information, see the SEC’s definition in Rule 4-10(a) (9) of Regulation S-X, a link for which is available at the SEC’s website.

“E&P” Exploration for and production of natural gas, oil and NGLs.

“Economically producible” The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities. For additional information, see the SEC’s definition in Rule 4-10(a) (10) of Regulation S-X, a link for which is available at the SEC’s website.

“Estimated ultimate recovery (EUR)” Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date. For additional information, see the SEC’s definition in Rule 4-10(a) (11) of Regulation S-X, a link for which is available at the SEC’s website.

“Exploitation” The development of a reservoir to extract its natural gas and/or oil.

“Exploratory well” An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section. For additional information, see the SEC’s definition in Rule 4-10(a) (13) of Regulation S-X, a link for which is available at the SEC’s website.

“Field” An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms *structural feature* and *stratigraphic condition* are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc. For additional information, see the SEC’s definition in Rule 4-10(a) (15) of Regulation S-X, a link for which is available at the SEC’s website.

“Gross well or acre” A well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest. For additional information, see the SEC’s definition in Item 1208(c)(1) of Regulation S-K, a link for which is available at the SEC’s website.

“Gross working interest” Gross working interest is the working interest in a given property plus the proportionate share of any royalty interest, including overriding royalty interest, associated with the working interest.

“Henry Hub” A common market pricing point for natural gas in the United States, located in Louisiana.

“Hydraulic fracturing” A process whereby fluids mixed with proppants are injected into a wellbore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.

“Infill drilling” Drilling wells in between established producing wells to increase recovery of natural gas, oil and NGLs from a known reservoir.

“MBbls” One thousand barrels of oil or other liquid hydrocarbons.

“Mcf” One thousand cubic feet of natural gas.

“Mcfe” One thousand cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

“MMBbls” One million barrels of oil or other liquid hydrocarbons.

“MMBtu” One million British thermal units (Btus).

"MMcf" One million cubic feet of natural gas.

"MMcfe" One million cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

"Mont Belvieu" A pricing point for North American NGLs.

"Net acres" The sum, for any area, of the products for each tract of the acres in that tract multiplied by the working interest in that tract. For additional information, see the SEC's definition in Item 1208(c)(2) of Regulation S-K, a link for which is available at the SEC's website.

"Net revenue interest" Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

"Net well" The sum, for all wells being discussed, of the working interests in those wells. For additional information, see the SEC's definition in Item 1208(c)(2) of Regulation S-K, a link for which is available at the SEC's website.

"NGL" Natural gas liquids.

"NYMEX" The New York Mercantile Exchange, on which spot and future contracts for natural gas and other commodities are traded.

"Operating interest" An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

"Overriding royalty interest" A fractional, undivided interest or right to production or revenues, free of costs, of a lessee with respect to an oil or natural gas well, that overrides a working interest.

"Play" A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and natural gas reserves.

"Present Value Index" or "PVI" A measure that is computed for projects by dividing the dollars invested into the PV-10 resulting or expecting to result from the investment by the dollars invested.

"Pressure pumping spread" All of the equipment needed to carry out a hydraulic fracturing job.

"Probabilistic estimate" The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence. For additional information, see the SEC's definition in Rule 4-10(a) (19) of Regulation S-X, a link for which is available at the SEC's website.

"Producing property" A natural gas and oil property with existing production.

"Productive wells" Producing wells and wells mechanically capable of production. For additional information, see the SEC's definition in Item 1208(c)(3) of Regulation S-K, a link for which is available at the SEC's website.

"Proppant" Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

"Proved developed producing" Proved developed reserves that can be expected to be recovered from a reservoir that is currently producing through existing wells.

"Proved developed reserves" Proved natural gas, oil and NGLs that are also developed natural gas, oil and NGL reserves.

"Proved natural gas, oil and NGL reserves" Proved natural gas, oil and NGL reserves are those quantities of natural gas, oil and NGLs that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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. Also referred to as "proved reserves." For additional information, see the SEC's definition in Rule 4-10(a) (22) of Regulation S-X, a link for which is available at the SEC's website.

"Proved reserves" See "proved natural gas, oil and NGL reserves."

"Proved undeveloped reserves" Proved natural gas, oil and NGL reserves that are also undeveloped natural gas, oil and NGL reserves.

"PV-10" When used with respect to natural gas, oil and NGL reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as "present value." After-tax PV-10 is also referred to as "standardized measure" and is net of future income tax expense.

"Reserve life index" The quotient resulting from dividing total reserves by annual production and typically expressed in years.

"Reserve replacement ratio" The sum of the estimated net proved reserves added through discoveries, extensions, infill drilling and acquisitions (which may include or exclude reserve revisions of previous estimates) for a specified period of time divided by production for that same period of time.

"Reservoir" A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs. For additional information, see the SEC's definition in Rule 4-10(a) (27) of Regulation S-X, a link for which is available at the SEC's website.

"Royalty interest" An interest in a natural gas and oil property entitling the owner to a share of natural gas, oil or NGL production free of production costs.

"Tcfe" One trillion cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

"Unconventional play" A play in which the targeted reservoirs generally fall into one of three categories: tight sands, coal beds, or shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates.

"Undeveloped acreage" Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. For additional information, see the SEC's definition in Item 1208(c)(4) of Regulation S-K, a link for which is available at the SEC's website.

"Undeveloped natural gas, oil and NGL reserves" Undeveloped natural gas, oil and NGL reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as "undeveloped reserves." For additional information, see the SEC's definition in Rule 4-10(a) (31) of Regulation S-X, a link for which is available at the SEC's website.

"Undeveloped reserves" See "undeveloped natural gas, oil and NGL reserves."

"Wells to sales" Wells that have been placed on sales for the first time.

"Working interest" An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.

"Workovers" Operations on a producing well to restore or increase production.

"WTI" West Texas Intermediate, the benchmark oil price in the United States.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

Natural gas, oil and NGL prices greatly affect our revenues and thus profits, liquidity, growth, ability to repay our debt and the value of our assets.

Our revenues, profitability, liquidity, growth, ability to repay our debt and the value of our assets greatly depend on prices for natural gas, oil and NGLs. The markets for these commodities are volatile, and we expect that volatility to continue. The prices of natural gas, oil and NGLs fluctuate in response to changes in supply and demand (global, regional and local), transportation costs, market uncertainty and other factors that are beyond our control. Short- and long-term prices are subject to a myriad of factors such as:

- overall demand, including the relative cost of competing sources of energy or fuel;
- overall supply, including costs of production;
- the availability, proximity and capacity of pipelines, other transportation facilities and gathering, processing and storage facilities;
- regional basis differentials;
- national and worldwide economic and political conditions;
- weather conditions and seasonal trends;
- government regulations, such as regulation of natural gas transportation and price controls;
- inventory levels; and
- market perceptions of future prices, whether due to the foregoing factors or others.

For example, in 2017 and 2016, the NYMEX settlement price ranged from a low of $1.71 per Mcf in March 2016 to a high of $3.93 per Mcf in January 2017, and during this period our production was 89% and 90% natural gas, respectively. Although we hedge a large portion of our production against changing prices, derivatives do not protect all our future volumes, may result in our forgoing profit opportunities if markets rise and, for NGLs, are not always available for substantial periods into the future.

In our exploration and production business, lower natural gas, oil and NGL prices directly reduce our revenues and thus our operating income and cash flow. Lower prices also reduce the projected profitability of further drilling and therefore are likely to reduce our drilling activity, which in turn means we will have fewer wells on production in the future. Lower prices also reduce the value of our assets, both by a direct reduction in what the production would be worth and by making some properties uneconomic, resulting in impairments to the recorded value of our reserves and non-cash charges to earnings. For example, in 2016, we reported non-cash impairment charges on our natural gas and oil properties totaling $2.3 billion, primarily resulting from decreases in trailing 12-month average first-day-of-the-month natural gas prices throughout 2016, as compared to 2015, and the impairment of certain undeveloped leasehold interests. Further impairments in subsequent periods could occur if the trailing 12-month commodity prices continue to fall as compared to the average used in prior periods.

In our Midstream segment, lower production by us and others can mean reduced volumes being transported in the gathering systems we operate and thus lower revenues.

As of December 31, 2017, we had $4.4 billion of debt outstanding, consisting principally of $3.2 billion in senior notes maturing in various increments from 2020 to 2027 and $1.2 billion in a term loan due in 2020. At current commodity price levels, our net cash flow from operations is substantially higher than our interest obligations under this debt, but significant drops in realized prices could affect our ability to pay our current obligations or refinance our debt as it becomes due.

Moreover, general industry conditions may make it difficult or costly to refinance increments of this debt as it matures. Although our indentures do not contain significant covenants restricting our operations and other activities, our bank credit agreements contain financial covenants with which we must comply. We refer you to the risk factor "Our current and future levels of indebtedness may adversely affect our results and limit our growth." Our inability to pay our current obligations or refinance our debt as it becomes due could have a material and adverse effect on our company. The drop in prices in the past three years has reduced our revenues, profits and cash flow, caused us to record significant asset impairments and led us to reduce both our level of capital investing and our workforce, which has caused us to incur significant expenses relating to employee terminations. Further price decreases could have similar consequences. Similarly, a rise in prices to levels experienced before the middle of 2014 could significantly increase our revenues, profits and cash flow, which could be used to expand capital investments.

Significant capital investment is required to replace our reserves and conduct our business.

Our activities require substantial capital investment. We intend to fund our future capital investing through net cash flows from operations net of changes in working capital. Our ability to generate operating cash flow is subject to many of the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. Future cash flows from operations are subject to a number of risks and variables, such as the level of production from existing wells, prices of natural gas, oil and NGLs, our success in developing and producing new reserves and the other risk factors discussed herein. If we are unable to fund capital investing, we could experience a further reduction in drilling new wells and acquiring new acreage, a loss of properties and a decline in our cash flow from operations and natural gas, oil and NGL production and reserves.

If we are not able to replace reserves, our production levels and thus our revenues and profits may decline.

Our future success depends largely upon our ability to find, develop or acquire additional natural gas, oil and NGL reserves that are economically recoverable. Unless we replace the reserves we produce through successful exploration, development or acquisition activities, our proved reserves and production will decline over time. Identifying and exploiting new reserves requires significant capital investment and successful drilling operations. Thus, our future natural gas, oil and NGL reserves and production, and therefore our revenues and profits, are highly dependent on our level of capital investments, our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

Our business depends on access to natural gas, oil and NGL transportation systems and facilities.

The marketability of our natural gas, oil and NGL production depends in large part on the operation, availability, proximity, capacity and expansion of transportation systems and facilities owned by third parties. For example, we can provide no assurance that sufficient transportation capacity will exist for expected production from the Appalachian Basin or that we will be able to obtain sufficient transportation capacity on economic terms. During the past two years, several planned pipelines intended to service production in the U.S. Northeast have been cancelled or had their in-service dates delayed due to regulatory delays and litigation.

Producers compete by lowering their sales prices, resulting in the locational differences from NYMEX pricing. Further, a lack of available capacity on transportation systems and facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these systems and facilities for an extended period of time could negatively affect our revenues. In addition, we have entered into contracts for firm transportation and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above.

A further downgrade in our credit rating could negatively impact our cost of and ability to access capital and our liquidity.

Actual or anticipated changes or downgrades in our credit ratings, including any announcement that our ratings are under further review for a downgrade, could impact our ability to access debt markets in the future, affect the market value of our senior notes and increase our corporate borrowing costs. Such ratings are limited in scope, and do not address all material risks relating to us, but rather reflect only the view of each rating agency at the time the rating is issued of the likelihood we will be able to repay our debt. An explanation of the significance of each rating may be obtained from the applicable rating agency. As of February 27, 2018, we were rated Ba3 by Moody's, BB- by Standard and Poor's and BB by Fitch Investor Services. There can be no assurance that such credit ratings will remain in effect for any given period of time or that such ratings will not be lowered, suspended or withdrawn entirely by the rating agencies, if, in each rating agency's judgment, circumstances so warrant.

Actual downgrades in our credit ratings may also impact our liquidity. Many of our existing commercial contracts contain, and future commercial contracts may contain, provisions permitting the counterparty to require increased security upon the occurrence of a downgrade in our credit rating. Providing additional security, such as posting letters of credit, could reduce our available cash or our liquidity under our revolving credit facility for other purposes. We had $323 million of letters of credit outstanding at December 31, 2017. The amount of additional security would depend on the severity of the downgrade from the credit rating agencies, and a downgrade could result in a decrease in our liquidity.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging in the face of shifting market conditions, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our future growth rate.

We necessarily must consider future price and cost environments when deciding how much capital we are likely to have available from net cash flow and how best to allocate it. Our current philosophy is to generally operate within cash flow from operations net of changes in working capital and to invest capital in projects only if they are projected to generate a PVI of 1.3 or greater, allocating generally to the highest PVI projects. Volatility in prices and potential errors in estimating costs, reserves or timing of production of the reserves could result in uneconomic projects or economic projects generating less than 1.3 PVI.

Certain of our undeveloped assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage.

Leases on approximately 1,864 net acres of our Fayetteville Shale acreage (excluding 158,231 net acres held on federal lands where activity is currently suspended by the Bureau of Land Management) will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. Approximately 31,536 and 39,255 net acres of our Northeast Appalachia and Southwest Appalachia acreage, respectively, will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. Our ability to drill wells depends on a number of factors, including certain factors that are beyond our control, such as the ability to obtain permits on a timely basis or to compel landowners or lease holders on adjacent properties to cooperate. Further, we may not have sufficient capital to drill all the wells necessary to hold the acreage without increasing our debt levels, or given price projections at the time, drilling may not be estimated to achieve a PVI of at least 1.3. To the extent we do not drill the wells, our rights to acreage can be lost.

Natural gas and oil drilling and producing operations and midstream operation can be hazardous and may expose us to liabilities.

Exploration and production operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, severe weather, natural disasters, groundwater contamination and other environmental hazards and risks. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, loss of equipment or otherwise negatively impacting the projected economic performance of our prospects. If any of these risks occurs, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources or equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

For our non-operated properties, we depend on the operator for operational and regulatory compliance.

Our midstream operations are subject to all of the risks and operational hazards inherent in transporting natural gas and ethane and natural gas compression, including:

- damages to pipelines, facilities and surrounding properties caused by third parties, severe weather, natural disasters, including hurricanes, and acts of terrorism;
- maintenance, repairs, mechanical or structural failures;
- damages to, loss of availability of and delays in gaining access to interconnecting third-party pipelines;
- disruption or failure of information technology systems and network infrastructure due to various causes, including unauthorized access or attack; and
- leaks of natural gas or ethane as a result of the malfunction of equipment or facilities.

A material event such as those described above could expose us to liabilities, monetary penalties or interruptions in our business operations. Although we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

Our current and future levels of indebtedness may adversely affect our results and limit our growth.

At December 31, 2017, we had long-term indebtedness of $4.4 billion, including borrowings of $1.2 billion under our term loan credit agreement. The terms of the indentures governing our outstanding senior notes, our credit facilities, and the lease agreements relating to our drilling rigs, other equipment and headquarters building, which we collectively refer to as our "financing agreements," impose restrictions on our ability and, in some cases, the ability of our subsidiaries to take a number of actions that we may otherwise desire to take, which may include, without limitation, one or more of the following:

- incurring additional debt;
- redeeming stock or redeeming certain debt;
- making certain investments;
- creating liens on our assets; and
- selling assets.

Under the revolving credit facility we entered into in December 2013, we must keep our total debt at or below 60% of our total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any non-cash impacts from certain full cost ceiling impairments, certain non-cash hedging activities and our pension and other post-retirement liabilities. Therefore, under the 2013 revolving credit facility, our adjusted capital structure as of December 31, 2017 was 31% debt and 69% equity. The term loan and revolving credit facility we entered into in June 2016 contain financial covenants that impose certain restrictions on us. In September 2017, we amended the 2016 credit agreement to reflect the following:

- increase the minimum interest coverage ratio to 2.00x commencing with the fiscal quarter ended June 30, 2017 and continued over the life of the 2016 credit facility;
- modify the minimum liquidity covenant such that either (1) if leverage is less than 4.00x or if the 2016 revolving credit facility has been terminated, there is no minimum liquidity covenant, or (2) we may elect to replace the minimum liquidity covenant with a maximum leverage ratio of no more than 5.50x for the fiscal quarter ending December 31, 2017, 5.00x for the fiscal quarters ending March 31, 2018 and June 30, 2018 and 4.50x thereafter; and
- modify the mandatory prepayment and commitment reduction provisions to permit us to retain the first $500 million of net cash proceeds from asset sales that would have otherwise been required to prepay amounts outstanding under the 2016 revolving credit facility and/or reduce commitments under the 2016 revolving credit facility.

Although we do not anticipate any violations of our financial covenants, our ability to comply with these covenants depends on the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas, oil and NGLs.

Although the indentures governing our senior notes contain covenants that apply to us, covenants limiting liens and sale and leaseback covenants contain exceptions and limitations that would allow us, pursuant to the terms of the indenture, to create, grant or incur certain liens or security interests. Moreover, the indentures do not contain any limitations on the ability of us or our subsidiaries to incur debt, pay dividends, make investments, or limit the ability of our subsidiaries to make distributions to us. Such activities may, however, be limited by our other financing agreements in certain circumstances.

Our level of indebtedness and off-balance sheet obligations, and the covenants contained in our financing agreements, could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments, thereby reducing the availability of cash flow for working capital, capital investing and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital investing, acquisitions and general corporate and other activities;

- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- detracting from our ability to successfully withstand a downturn in our business or the economy generally.

Our ability to comply with the covenants and other restrictions in our financing agreements may be affected by events beyond our control, including prevailing economic and financial conditions.

If we fail to comply with the covenants and other restrictions, it could lead to an event of default and the acceleration of our obligations under the notes or our other financing agreements, and in the case of the lease agreements for drilling rigs, compressors and pressure pumping equipment, loss of use of the equipment. In particular, a significant or extended decline in natural gas, oil or NGL prices would have a material adverse effect on our results of operations, our access to capital and the quantities of natural gas, oil and NGLs that we can produce economically. For example, the New York Mercantile Exchange, or NYMEX, natural gas prices traded at a low of $1.71 per Mcf in March 2016 to a high of $3.93 per Mcf in January 2017 based on the settlement price of the monthly contract at expiration. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure that we will be able to generate sufficient cash flow to pay the interest on our debt, to meet our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations. The terms of our financing agreements may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure that any such proposed offering, refinancing or sale of assets can be successfully completed or, if completed, that the terms will be favorable to us.

We have made significant investments in pipelines and gathering systems and contracts and in oilfield service businesses, including our drilling rigs, pressure pumping equipment and sand mine operations, to lower costs and secure inputs for our operations and transportation for our production. If our exploration and production activities are curtailed or disrupted, we may not recover our investment in these activities, which could adversely impact our results of operations. In addition, our continued expansion of these operations may adversely impact our relationships with third-party providers.

Through December 31, 2017, we had invested approximately $1.3 billion in our gas gathering system built for the Fayetteville Shale. We may make further substantial investments in the expansion of this system. Our ability to recover the costs of these investments depends on production from the Fayetteville Shale, and reduced production volumes, whether due to lower drilling activity due to lower prices or failure to produce significant quantities of gas in relevant timeframes, can adversely affect our ability to recover these investments.

We also have entered into gathering agreements in other producing areas and multiple long-term firm transportation agreements relating to natural gas volumes from all our producing areas. As of December 31, 2017, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately $9.2 billion. If our development programs fail to produce sufficient quantities of natural gas and ethane within expected timeframes, we could be forced to pay demand or other charges for transportation on pipelines and gathering systems that we would not be using.

We also have made significant investments to meet certain of our field services' needs, including establishing our own drilling rig operation, sand mine and pressure pumping capability. Reductions in our operating plans caused by the current commodity price environment have impacted our ability to fully utilize some of this equipment and has reduced the need for sand and other services. If our level of operations is reduced for a long period, we may not be able to recover these investments. Further, our presence in these service and supply sectors, including competing with them for qualified personnel and supplies, may have an adverse effect on our relationships with our existing third-party service and resource providers or our ability to secure these services and resources from other providers.

Our business depends on the availability of water and the ability to dispose of water. Limitations or restrictions on our ability to obtain or dispose of water may have an adverse effect on our financial condition, results of operations and cash flows.

With current technology, water is an essential component of drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water, or to dispose of or recycle water after use, could adversely impact our operations. In some cases, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Moreover, the introduction of new environmental initiatives and regulations related to water acquisition or waste water disposal, including produced water, drilling fluids and other wastes associated with the exploration, development or production of hydrocarbons, could limit or prohibit our ability to utilize hydraulic fracturing or waste water injection control wells.

In addition, concerns have been raised about the potential for underground injection wells, a predominant method for disposing of waste water from natural gas and oil activities, to cause seismic activity. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others. We operate injection wells and utilize injection wells owned by third parties to dispose of waste water associated with our operations, subject to regulatory restrictions relating to seismic activity.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of water necessary for hydraulic fracturing of wells or the disposal of water may increase our operating costs or may cause us to delay, curtail or discontinue our exploration and development plans, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our producing properties are concentrated in two regions, the Appalachian Basin and the Fayetteville Shale, making us vulnerable to risks associated with operating in limited geographic areas.

Our producing properties are geographically concentrated in the Fayetteville Shale in Arkansas and the Appalachian Basin in Pennsylvania and West Virginia. At December 31, 2017, 75% of our total estimated proved reserves were attributable to properties located in the Appalachian Basin and 25% in the Fayetteville Shale. As a result of this concentration in two primary regions, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, state politics, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or interruption of the processing or transportation of natural gas, oil or NGLs.

Competition in the oil and natural gas industry is intense, making it more difficult for us to market natural gas, oil and NGLs, to secure trained personnel and appropriate services, to obtain additional properties and to raise capital.

Our cost of operations is highly dependent on third-party services, and as activity in our industry increases, competition for these services may increase. Similarly, we must have trained, qualified personnel, and as commodity prices rise, competition for this talent also increases. Our ability to acquire and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas, oil and NGLs and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and gas industry. Certain of our competitors may possess and employ financial, technical and personnel resources greater than ours. Those companies may be able to pay more for personnel, property and services and to attract capital at lower rates. This may become more likely if prices for oil and NGLs recover faster than prices for natural gas, as natural gas comprises a far greater percentage of our overall production than it does for most of the companies with whom we compete for talent.

Climate change legislation or regulations governing the emissions of greenhouse gases could result in increased operating costs and reduce demand for the natural gas, oil and NGLs we produce, and concern in financial and investment markets over greenhouse gasses and fossil fuel production could adversely affect our access to capital and the price of our common stock.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration, or PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their greenhouse gas emissions also will be required to meet “best available control technology” standards that will be established on a case-by-case basis. One of our subsidiaries operates compressor stations, which are facilities that are required to adhere to the PSD or Title V permit requirements. EPA rulemakings related to greenhouse gas emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

The EPA also has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore natural gas and oil production sources in the United States on an annual basis, which include certain of our operations. In May 2016, the EPA finalized additional regulations to control methane and volatile organic compound emissions from certain oil and gas equipment and operations.

Although Congress from time to time has considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of states, including states in which we operate, have enacted or passed measures to track and reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and regional greenhouse gas cap-and-trade programs. Most of these cap-and-trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. These reductions may cause the cost of allowances to escalate significantly over time.

The adoption and implementation of regulations that require reporting of greenhouse gases or otherwise limit emissions of greenhouse gases from our equipment and operations could require us to incur costs to monitor and report on greenhouse gas emissions or install new equipment to reduce emissions of greenhouse gases associated with our operations. In addition, these regulatory initiatives could drive down demand for our products by stimulating demand for alternative forms of energy that do not rely on combustion of fossil fuels that serve as a major source of greenhouse gas emissions, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. At the same time, new laws and regulations are prompting power producers to shift from coal to natural gas, which is increasing demand.

In December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions (the “Paris Agreement”). The Paris Agreement entered into force in November 2016 after more than 70 nations, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. In June 2017, President Trump announced that the United States intends to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or a separate agreement. In August 2017, the U.S. Department of State officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time. To the extent that the United States and other countries implement this agreement or impose other climate change regulations on the oil and natural gas industry, it could have an adverse effect on our business.

Separate from actual and possible governmental action, certain financial institutions have announced policies to cease investing or to divest investments in companies, such as ours, that produce fossil fuels, and some banks have announced they no longer will lend to companies in this sector. To date these represent small fractions of overall sources of equity and debt, but that fraction could grow and thus affect our access to capital. Moreover, some equity investors are expressing concern over these matters and may prompt companies in our industry to adopt more costly practices even absent governmental action. Although we believe our practices result in low emission rates for methane and other greenhouse gases, complying with investor sentiment may require modifications to our practices, which could increase our capital and operating expenses.

Volatility in the financial markets or in global economic factors could adversely impact our business and financial condition.

Our business may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are reduced energy demand and lower commodity prices, increased difficulty in collecting amounts owed to us by our customers and reduced access to credit markets. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures.

We are subject to complex federal, state and local laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our natural gas and oil exploration and production operations are subject to complex and stringent federal, state and local laws and regulations, including those governing environmental protection, the occupational health and safety aspects of our operations, the discharge of materials into the environment, and the protection of certain plant and animal species. See “Other — Environmental Regulation” in Item 1 of Part I of this Annual Report for a description of the laws and regulations that affect us. These laws and regulations require us to obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Environmental regulations may restrict the types, quantities and concentration of materials that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenues.

Failure to comply with laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including investigatory actions, the assessment of monetary penalties, the imposition of remedial requirements, or the issuance of orders or judgments limiting or enjoining future operations. Strict liability or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of our own actions. Moreover, our costs of compliance with existing laws could be substantial and may increase or unforeseen liabilities could be imposed if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. If we are not able to recover the increased costs through insurance or increased revenues, our business, financial condition, results of operations and cash flows could be adversely affected.

Our proved natural gas, oil and NGL reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated.

As described in more detail under "Critical Accounting Policies and Estimates – Natural Gas and Oil Properties" in Item 7 of Part II of this Annual Report, our reserve data represents the estimates of our reservoir engineers made under the supervision of our management, and our reserve estimates are audited each year by Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm. Reserve engineering is a subjective process of estimating underground accumulations of natural gas, oil and NGLs that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas, oil and NGL prices. Additional assumptions include drilling and operating expenses, capital investing, taxes and availability of funds. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas, oil and NGLS that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas, oil and NGL reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average natural gas, oil and NGL index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the applicable accounting standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Our commodity price risk management and measurement systems and economic hedging activities might not be effective and could increase the volatility of our results.

We currently seek to hedge the price of a significant portion of our estimated production, through swaps, collars, floors and other derivative instruments. The systems we use to quantify commodity price risk associated with our businesses might not always be followed or might not always be effective. Further, such systems do not in themselves manage risk, particularly risks outside of our control, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, changes in interest rates and other risks discussed in this report might still adversely affect our earnings, cash flows and balance sheet under applicable accounting rules, even if risks have been identified. Furthermore, no single hedging arrangement can adequately address all risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract's counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist.

Our use of derivatives, through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under GAAP to the extent that such hedges are not fully effective in offsetting changes to the value of the hedged commodity, as well as changes in the fair value of derivatives that do not qualify or have not been designated as hedges under GAAP, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to us has occurred during the applicable period.

The impact of changes in market prices for oil, natural gas and NGLs on the average prices paid or received by us may be reduced based on the level of our hedging activities. These hedging arrangements may limit or enhance our margins if the market prices for oil, natural gas or NGLs were to change substantially from the price established by the hedges. In addition, our hedging arrangements expose us to the risk of financial loss if our production volumes are less than expected.

We may be unable to dispose of assets on attractive terms, and may be required to retain liabilities for certain matters.

Various factors could materially affect our ability to dispose of assets if and when we decide to do so, including the availability of purchasers willing to purchase the assets at prices acceptable to us, particularly in times of reduced and volatile commodity prices. Sellers typically retain certain liabilities for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

The implementation of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act established federal oversight and regulation of the over-the-counter ("OTC") derivatives market and entities, including us, which participate in that market. The Dodd-Frank Act requires the CFTC, the SEC, and other regulatory authorities to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized most of its regulations under the Dodd-Frank Act, it continues to review and refine its initial rulemakings through additional interpretations and supplemental rulemakings. As a result, it is not possible at this time to predict the ultimate effect of the rules and regulations on our business and while most of the regulations have been adopted, any new regulations or modifications to existing regulations may increase the cost of derivative contracts, limit the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and the regulations thereunder, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital investing.

In December 2016, the CFTC re-proposed new rules that would place federal limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions and finalized a companion rule on aggregation of positions among entities under common ownership or control. If finalized, the position limits rule may have an impact on our ability to hedge our exposure to certain enumerated commodities.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and mandatory trading on designated contract markets or swap execution facilities. The CFTC may designate additional classes of swaps as subject to the mandatory clearing requirement in the future, but has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. The CFTC and prudential banking regulators also adopted mandatory margin requirements on uncleared swaps between swap dealers and certain other counterparties. The margin requirements are currently effective with respect to certain market participants and will be phased in over time with respect to other market participants, based on the level of an entity's swaps activity. We expect to qualify for and rely upon an end-user exception from the mandatory clearing and trade execution requirements for swaps entered to hedge our commercial risks. We also should qualify for an exception from the uncleared swaps margin requirements. However, the application of the mandatory clearing and trade execution requirements and the uncleared swaps margin requirement to other market participants, such as swap dealers, may adversely affect the cost and availability of the swaps that we use for hedging.

Certain aspects of the recently passed comprehensive tax reform bill could adversely affect our business and financial condition.

On December 22, 2017, President Trump signed into law H.R. 1 (commonly referred to as the "Tax Cuts and Jobs Act," or the "Tax Reform"), a comprehensive tax reform bill that significantly reforms the Internal Revenue Code of 1986, as amended. The Tax Reform, among other things, contains significant changes to corporate taxation, including a permanent reduction of the corporate income tax rate, a partial limitation on the deductibility of business interest expense, limitation of the deduction for certain net operating losses to 80% of current year taxable income for tax years 2018 and beyond, an indefinite net operating loss carryforward, immediate deductions for certain new investments instead of deductions for depreciation expense over time and the modification or repeal of many business deductions and credits. We continue to examine the impact of this legislation, and as certain aspects of it are uncertain and subject to future regulations, we note that the Tax Reform could adversely affect our business and financial condition.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

The elimination of certain key U.S. federal income tax deductions currently available to oil and natural gas exploration and production companies may be proposed in the future. These changes may include, among other proposals:

- repeal of the percentage depletion allowance for natural gas and oil properties;
- elimination of current deductions for intangible drilling and development costs;
- elimination of the deduction for certain domestic production activities; and
- extension of the amortization period for certain geological and geophysical expenditures.

The passage of these or any similar changes in U.S. federal income tax laws to eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development could have an adverse effect on our financial position, results of operations and cash flows.

We may experience adverse or unforeseen tax consequences due to further developments affecting our deferred tax assets that could significantly affect our results.

Deferred tax assets, including net operating loss carryforwards, represent future savings of taxes that would otherwise be paid in cash. At December 31, 2017, we had substantial amounts of net operating loss carryforwards for U.S. federal and state income tax purposes. Limitations may exist upon use of these carryforwards in the event that a change in control of the Company occurs. Additionally, due to the Tax Reform's permanent reduction of the corporate income tax rate, we were required to write down our deferred tax assets (including our net operating loss carryforwards), and there may be other material adverse effects on our deferred tax assets resulting from the Tax Reform that we have not yet identified.

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. At December 31, 2017, we recorded a valuation allowance against our entire deferred tax asset, including the portion related to the remaining net operating loss carryforwards. This allowance was recorded primarily as a result of cumulative book losses experienced over the three-year period ending December 31, 2016. If we experience additional book losses, we may be required to increase our valuation allowance against our deferred tax assets.

Our existing deferred tax asset valuation allowance may also be reversed if significant events occur or market conditions change materially, and our current or future earnings are, or are projected to be, significantly higher than we currently estimate. This reversal may result in a significant one-time favorable impact positively affecting our consolidated results of operations for the period of reversal and for the full fiscal year results.

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

Our business has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We depend on digital technology, including information systems and related infrastructure as well as cloud applications and services, to process and record financial and operating data, analyze seismic and drilling information, conduct reservoir modeling and reserves estimation, communicate with employees and business associates, perform compliance reporting and in many other activities related to our business. Our business associates, including vendors, service providers, purchasers of our production, and financial institutions are also dependent on digital technology.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. Our technologies, systems, networks, and those of our business associates may become the target of cyber-attacks or information security breaches, which could lead to disruptions in critical systems, unauthorized release of confidential or protected information, corruption of data or other disruptions of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber-attack involving our information systems and related infrastructure, or that of our business associates, could disrupt our business and negatively impact our operations in a variety of ways, including:

- unauthorized access to seismic data, reserves information, strategic information or other sensitive or proprietary information could have a negative impact on our ability to compete for natural gas and oil resources;

- unauthorized access to personal identifying information of royalty owners, employees and vendors, which could expose us to allegations that we did not sufficiently protect that information;
- data corruption or operational disruption of production infrastructure could result in loss of production, or accidental discharge;
- a cyber-attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects; and
- a cyber-attack on a third party gathering, pipeline or rail service provider could delay or prevent us from marketing our production, resulting in a loss of revenues.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability, which could have a material adverse effect on our financial condition, results of operations or cash flows.

To date we have not experienced any material losses relating to cyber-attacks; however, there can be no assurance that we will not suffer such losses in the future. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, seismicity, oil spills and explosions of natural gas transmission lines, may lead to regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

Common stockholders will be diluted if additional shares are issued.

From time to time we have issued stock to raise capital for our business, including significant offerings of new shares in 2015 and 2016. We also issue restricted stock, options and performance share units to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Anti-takeover provisions in our organizational documents and under Delaware law may impede or discourage a takeover, which could cause the market price of our common stock to decline.

We are a Delaware corporation, and the anti-takeover provisions of Delaware law impose various impediments to the ability of a third party to acquire control of us, even if a change in control would be beneficial to our existing stockholders, which, under certain circumstances, could reduce the market price of our common stock. In addition, protective provisions in our Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws or the implementation by our board of directors of a stockholder rights plan that could deter a takeover.

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ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES

The summary of our oil and natural gas reserves as of fiscal year-end 2017 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed "2017 Proved Reserves by Category and Summary Operating Data" in "Business – Exploration and Production – Our Proved Reserves" in Item 1 of this Annual Report and incorporated by reference into this Item 2.

The information regarding our proved undeveloped reserves required by Item 1203 of Regulation S-K is included under the heading "Proved Undeveloped Reserves" in "Business – Exploration and Production – Our Proved Reserves" in Item 1 of this Annual Report.

The information regarding delivery commitments required by Item 1207 of Regulation S-K is included under the heading "Sales, Delivery Commitments and Customers" in the "Business – Exploration and Production – Our Operations" in Item 1 of this Annual Report and incorporated by reference into this Item 2. For additional information about our natural gas and oil operations, we refer you to "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report. For information concerning capital investments, we refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Investments." We also refer you to Item 6, "Selected Financial Data" in Part II of this Annual Report for information concerning natural gas, oil and NGLs produced.

The information regarding natural gas and oil properties, wells, operations and acreage required by Item 1208 of Regulation S-K is set forth below:

Leasehold acreage as of December 31, 2017

	Undeveloped		Developed		**Total**	
	Gross	Net	Gross	Net	**Gross**	**Net**
Northeast Appalachia	113,298	87,927	108,422	103,299	**221,720**	**191,226**
Southwest Appalachia	443,328	219,709	100,244	70,582	**543,572**	**290,291**
Fayetteville Shale [1]	504,484	424,858	849,280	492,984	**1,353,764**	**917,842**
Other:						
US – Other Exploration	534,265	202,911	–	–	**534,265**	**202,911**
US – Brown Dense	131,043	97,234	7,604	6,377	**138,647**	**103,611**
US – Sand Wash Basin	97,120	69,091	15,028	10,691	**112,148**	**79,782**
Canada – New Brunswick [2]	2,518,519	2,518,519	–	–	**2,518,519**	**2,518,519**
	4,342,057	3,620,249	1,080,578	683,933	**5,422,635**	**4,304,182**

(1) Fayetteville Shale gross acres includes additional developable lands as a result of Arkansas Oil & Gas Commission Integration Orders.

(2) The exploration licenses for 2,518,519 net acres in New Brunswick, Canada, have been subject to a moratorium since 2015.

Lease Expirations

The following table summarizes the leasehold expiring over the next three years, assuming successful wells are not drilled to develop the acreage and leases are not extended:

	For the years ended December 31,		
Net acreage expiring:	2018	2019	2020
Northeast Appalachia	15,731	10,852	4,953
Southwest Appalachia (1)	12,552	14,247	12,456
Fayetteville Shale (2)	262	859	743
Other:			
US – Other Exploration	62,583	104,798	16,212
US – Brown Dense	83,023	5,850	3,196
US – Sand Wash Basin	4,998	4,435	1,000
Canada – New Brunswick (3)	–	–	–

(1) Of this acreage, 2,666 net acres in 2018, 5,907 net acres in 2019 and 1,850 net acres in 2020 can be extended for an average of 5.9 years.

(2) This excludes 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management.

(3) Exploration licenses for 2,518,519 net acres were extended through 2021 but have been subject to a moratorium since 2015.

Producing wells as of December 31, 2017

	Natural Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Appalachia:							
Northeast	600	531	–	–	600	531	538
Southwest	387	272	–	–	387	272	360
Fayetteville Shale	4,698	3,243	–	–	4,698	3,243	4,033
Other	10	7	14	14	24	21	22
	5,695	4,053	14	14	5,709	4,067	4,953

The information regarding drilling and other exploratory and development activities required by Item 1205 of Regulation S-K is set forth below:

	Exploratory					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2017						
Appalachia:						
Northeast	–	–	–	–	–	–
Southwest	–	–	–	–	–	–
Fayetteville Shale	–	–	–	–	–	–
Other	1.0	1.0	–	–	1.0	1.0
Total	1.0	1.0	–	–	1.0	1.0
2016						
Appalachia:						
Northeast	1.0	1.0	–	–	1.0	1.0
Southwest	–	–	–	–	–	–
Fayetteville Shale	–	–	–	–	–	–
Other	–	–	–	–	–	–
Total	1.0	1.0	–	–	1.0	1.0
2015						
Appalachia:						
Northeast	1.0	1.0	–	–	1.0	1.0
Southwest	–	–	–	–	–	–
Fayetteville Shale	–	–	–	–	–	–
Other	2.0	2.0	–	–	2.0	2.0
Total	3.0	3.0	–	–	3.0	3.0

	Development					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2017						
Appalachia:						
Northeast	83.0	80.8	–	–	83.0	80.8
Southwest	57.0	43.6	–	–	57.0	43.6
Fayetteville Shale	25.0	24.1	–	–	25.0	24.1
Other	–	–	–	–	–	–
Total	165.0	148.5	–	–	165.0	148.5
2016						
Appalachia:						
Northeast	23.0	22.9	–	–	23.0	22.9
Southwest	18.0	13.4	–	–	18.0	13.4
Fayetteville Shale	43.0	35.2	–	–	43.0	35.2
Other	–	–	–	–	–	–
Total	84.0	71.5	–	–	84.0	71.5
2015						
Appalachia:						
Northeast	99.0	98.5	–	–	99.0	98.5
Southwest	63.0	36.6	–	–	63.0	36.6
Fayetteville Shale	265.0	209.4	–	–	265.0	209.4
Other	–	–	–	–	–	–
Total	427.0	344.5	–	–	427.0	344.5

The following table presents the information regarding our present activities required by Item 1206 of Regulation S-K:

Wells in progress as of December 31, 2017

	Gross	Net
Drilling:		
Appalachia:		
Northeast	42.0	42.0
Southwest	23.0	18.3
Fayetteville Shale	–	–
Other	–	–
Total	65.0	60.3
Completing:		
Appalachia:		
Northeast	10.0	10.0
Southwest	17.0	12.7
Fayetteville Shale	–	–
Other	–	–
Total	27.0 (1)	22.7
Drilling & Completing:		
Appalachia:		
Northeast	52.0	52.0
Southwest	40.0	31.0
Fayetteville Shale	–	–
Other	–	–
Total	92.0	83.0

(1) Includes 19 gross wells that are waiting on pipeline or production facilities.

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The information regarding oil and gas production, production prices and production costs required by Item 1204 of Regulation S-K is set forth below:

Production, Average Sales Price and Average Production Cost

	For the years ended December 31,		
	2017	2016	2015
Natural Gas			
Production *(Bcf)*:			
Northeast Appalachia	**395**	350	360
Southwest Appalachia	**85**	62	67
Fayetteville Shale	**316**	375	465
Other	**1**	1	7
Total	**797**	788	899
Average realized gas price per Mcf, excluding derivatives:			
Northeast Appalachia	**$ 2.11**	$ 1.34	$ 1.62
Southwest Appalachia	**2.28**	1.71	1.92
Fayetteville Shale	**2.35**	1.80	2.12
Total	**$ 2.23**	$ 1.59	$ 1.91
Average realized gas price per Mcf, including derivatives	**$ 2.19**	$ 1.64	$ 2.37
Oil			
Production *(MBbls)*:			
Southwest Appalachia	**2,228**	2,041	2,036
Other	**99**	151	229
Total	**2,327**	2,192	2,265
Average realized oil price per Bbl:			
Southwest Appalachia	**$ 42.93**	$ 30.59	$ 31.80
Other	**47.38**	39.44	46.21
Total	**$ 43.12**	$ 31.20	$ 33.25
NGL			
Production *(MBbls)*:			
Southwest Appalachia	**14,193**	12,317	10,640
Other	**52**	55	62
Total	**14,245**	12,372	10,702
Average realized NGL price per Bbl, excluding derivatives:			
Southwest Appalachia	**$ 14.42**	$ 7.41	$ 6.76
Other	**26.38**	17.33	14.51
Total	**$ 14.46**	$ 7.46	$ 6.80
Total Production *(Bcfe)*			
Northeast Appalachia	**395**	350	360
Southwest Appalachia	**183**	148	143
Fayetteville Shale	**316**	375	465
Other	**3**	2	8
Total	**897**	875	976
Average Production Cost			
Cost per Mcfe, excluding ad valorem and severance taxes:			
Northeast Appalachia	**$ 0.75**	$ 0.76	$ 0.71
Southwest Appalachia	**1.07**	1.05	1.39
Fayetteville Shale	**0.97**	0.89	0.91
Total	**$ 0.90**	$ 0.87	$ 0.92

During 2017, we were required to file Form 23, "Annual Survey of Domestic Oil and Gas Reserves," with the U.S. Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report. The primary differences are that Form 23 reports gross reserves, including the royalty owners' share, and includes reserves for only those properties of which we are the operator.

Miles of Pipe

As of December 31, 2017, our Midstream segment had 2,045 miles and 16 miles of pipe in its gathering systems located in Arkansas and Louisiana, respectively.

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which we believe do not materially interfere with the use of or affect the value of such properties. Substantially all our Fayetteville Shale properties are subject to liens securing the credit facility we entered into in 2016. Prior to acquiring undeveloped properties, we endeavor to perform a title investigation that is thorough but less vigorous than that we endeavor to conduct prior to drilling, which is consistent with standard practice in the oil and natural gas industry. Generally, before we commence drilling operations on properties that we operate, we conduct a title examination and perform curative work with respect to significant defects that we identify. We believe that we have performed title review with respect to substantially all of our active properties that we operate.

ITEM 3. LEGAL PROCEEDINGS

We are subject to litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. Management believes that such litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated.

We are also subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position or results of operations.

See "Litigation" in Note 8, "Commitments and Contingencies" in the consolidated financial statements for further details on our current legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Our sand mining operations in support of our E&P business are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95.1 to this Annual Report.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange (the "NYSE") under the symbol "SWN." On February 27, 2018, the closing price of our common stock trading under the symbol "SWN" was $3.69 and we had 3,202 stockholders of record. The following table presents, for each of the periods indicated, the high and low reported sales prices for our common stock trading under the symbol "SWN" as reported on the NYSE:

	Range of Market Prices					
Quarter Ended	**2017**		2016		2015	
	High	**Low**	High	Low	High	Low
March 31	**$ 10.68**	**$ 7.20**	$ 9.90	$ 5.30	$ 28.02	$ 21.46
June 30	**$ 8.94**	**$ 5.47**	$ 15.45	$ 7.55	$ 29.61	$ 22.40
September 30	**$ 6.39**	**$ 5.00**	$ 15.59	$ 11.42	$ 22.84	$ 11.84
December 31	**$ 6.72**	**$ 4.90**	$ 14.40	$ 9.14	$ 13.90	$ 5.00

We currently do not pay dividends on our common stock.

Issuer Purchases of Equity Securities

The table below sets forth information with respect to purchases of our common stock made by us or on our behalf during the quarter ended December 31, 2017:

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	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 2017	10,717	$ 5.85	n/a	n/a
November 2017	–	$ –	n/a	n/a
December 2017	232,025	$ 6.19	n/a	n/a
Total fourth-quarter 2017:	242,742	$ 6.17	n/a	n/a

(1) Reflects shares retired by us to satisfy applicable tax withholding obligations due on employee stock plan share issuances. All changes in common stock in treasury in 2017 were due to purchases and sales of shares held on behalf of participants in a non-qualified deferred compensation supplemental retirement savings plan.

Recent Sales of Unregistered Equity Securities

We did not sell any unregistered equity securities during 2017, 2016 or 2015. See Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters," in Part III of this Annual Report for information regarding our equity compensation plans as of December 31, 2017.

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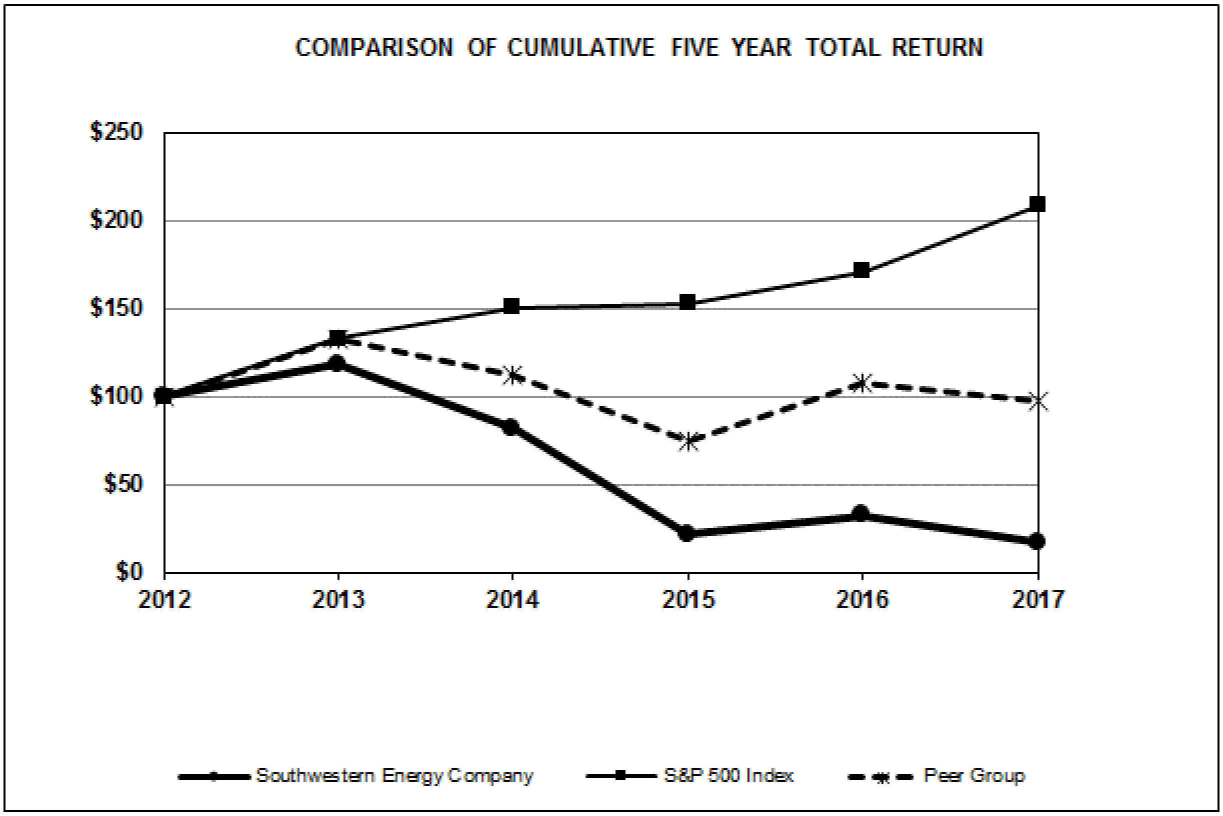
STOCK PERFORMANCE GRAPH

The following graph compares, for the last five years, the performance of our common stock to the S&P 500 Index and our peer group. Our peer group consists of Anadarko Petroleum Corporation, Apache Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., Concho Resources Inc., Continental Resources Inc., Denbury Resources Inc., Devon Energy Corporation, EOG Resources, Inc., EQT Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Co., QEP Resources, Inc., Range Resources Corporation, Sandridge Energy, Inc., SM Energy Company, Ultra Petroleum Corp., Whiting Petroleum Corporation and WPX Energy, Inc. The chart assumes that the value of the investment in our common stock and each index was $100 at December 31, 2012, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance:



	12/31/12	12/31/13	12/31/14	12/31/15	12/31/16	**12/31/17**
Southwestern Energy Company	$ 100	$ 118	$ 82	$ 21	$ 32	$ **17**
S&P 500 Index	100	132	151	153	171	**208**
Peer Group	100	132	112	74	108	**97**

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2017. This information and the notes thereto are derived from our consolidated financial statements. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Financial Statements and Supplementary Data."

	2017	2016	2015	2014	2013
	(in millions except shares, per share, stockholder data and percentages)				
Financial Review					
Operating revenues:					
Exploration and production	**$ 2,086**	$ 1,413	$ 2,074	$ 2,862	$ 2,404
Midstream	**3,198**	2,569	3,119	4,358	3,347
Intersegment revenues	**(2,081)**	(1,546)	(2,060)	(3,182)	(2,380)
	3,203	2,436	3,133	4,038	3,371
Operating costs and expenses:					
Marketing purchases – midstream	**976**	864	852	980	782
Operating and general and administrative expenses	**904**	839	935	648	519
Restructuring charges	**–**	78	–	–	–
Depreciation, depletion and amortization	**504**	436	1,091	942	787
Impairment of natural gas and oil properties	**–**	2,321	6,950	–	–
Gain on sale of assets, net	**(6)**	–	(283)	–	–
Taxes, other than income taxes	**94**	93	110	95	79
	2,472	4,631	9,655	2,665	2,167
Operating income (loss)	**731**	(2,195)	(6,522)	1,373	1,204
Interest expense, net	**135**	88	56	59	42
Gain (loss) on derivatives	**422**	(339)	47	139	26
Loss on early extinguishment of debt	**(70)**	(51)	–	–	–
Other income (loss), net	**5**	1	(30)	(4)	2
Income (loss) before income taxes	**953**	(2,672)	(6,561)	1,449	1,190
Provision (benefit) for income taxes:					
Current	**(22)**	(7)	(2)	21	(11)
Deferred	**(71)**	(22)	(2,003)	504	497
	(93)	(29)	(2,005)	525	486
Net income (loss)	**1,046**	(2,643)	(4,556)	924	704
Mandatory convertible preferred stock dividend	**108**	108	106	–	–
Participating securities – mandatory convertible preferred stock	**123**	–	–	–	–
Net income (loss) attributable to common stock	**$ 815**	$ (2,751)	$ (4,662)	$ 924	$ 704
Net cash provided by operating activities	**$ 1,097**	$ 498	$ 1,580	$ 2,335	$ 1,909
Net cash used in investing activities	**$ (1,252)**	$ (162)	$ (1,638)	$ (7,288)	$ (2,216)
Net cash provided by (used in) financing activities	**$ (352)**	$ 1,072	$ 20	$ 4,983	$ 277
Common Stock Statistics					
Earnings per share:					
Net income (loss) attributable to common stockholders – Basic	**$ 1.64**	$ (6.32)	$ (12.25)	$ 2.63	$ 2.01
Net income (loss) attributable to common stockholders – Diluted	**$ 1.63**	$ (6.32)	$ (12.25)	$ 2.62	$ 2.00
Book value per average diluted share	**$ 3.95**	$ 2.11	$ 6.00	$ 13.23	$ 10.32
Market price at year-end	**$ 5.58**	$ 10.82	$ 7.11	$ 27.29	$ 39.33
Number of stockholders of record at year-end	**3,216**	3,292	3,415	3,271	3,259
Average diluted shares outstanding	**500,804,297**	435,337,402	380,521,039	352,410,683	351,101,452

	2017	2016	2015	2014	2013
Capitalization *(in millions)*					
Total debt	**$ 4,391**	$ 4,653	$ 4,705	$ 6,957	$ 1,940
Total equity	**1,979**	917	2,282	4,662	3,622
Total capitalization	**$ 6,370**	$ 5,570	$ 6,987	$ 11,619	$ 5,562
Total assets	**$ 7,521**	$ 7,076	$ 8,086	$ 14,915	$ 8,037
Capitalization ratios:					
Debt	**69%**	84%	67%	60%	35%
Equity	**31%**	16%	33%	40%	65%
Capital Investments *(in millions)* (1)					
Exploration and production	**1,248**	623	2,258	7,254	2,052
Midstream services	**32**	21	167	144	158
Other	**13**	4	12	49	25
	$ 1,293	$ 648	$ 2,437	$ 7,447	$ 2,235
Exploration and Production					
Natural gas:					
Production *(Bcf)*	**797**	788	899	766	656
Average realized price per Mcf, including derivatives	**$ 2.19**	$ 1.64	$ 2.37	$ 3.72	$ 3.65
Average realized price per Mcf, excluding derivatives	**$ 2.23**	$ 1.59	$ 1.91	$ 3.74	$ 3.17
Oil:					
Production *(MBbls)*	**2,327**	2,192	2,265	235	138
Average price per barrel	**$ 43.12**	$ 31.20	$ 33.25	$ 79.91	$ 103.32
NGL:					
Production *(MBbls)*	**14,245**	12,372	10,702	231	50
Average price per barrel, including derivatives	**$ 14.48**	$ 7.46	$ 6.80	$ 15.72	$ 43.63
Average price per barrel, excluding derivatives	**$ 14.46**	$ 7.46	$ 6.80	$ 15.72	$ 43.63
Total production *(Bcfe)*	**897**	875	976	768	657
Lease operating expenses per Mcfe	**$ 0.90**	$ 0.87	$ 0.92	$ 0.91	$ 0.86
General and administrative expenses per Mcfe	**$ 0.22** (2)	$ 0.22 (3)	$ 0.21	$ 0.24	$ 0.24
Taxes, other than income taxes per Mcfe	**$ 0.10**	$ 0.10 (4)	$ 0.10	$ 0.11	$ 0.10
Proved reserves at year-end:					
Natural gas *(Bcf)*	**11,126**	4,866	5,917	9,809	6,974
Oil *(MMBbls)*	**65.6**	10.5	8.8	37.6	0.4
NGLs *(MMBbls)*	**542.4**	53.9	40.9	118.7	–
Total reserves *(Bcfe)*	**14,775**	5,253	6,215	10,747	6,976
Midstream Services					
Volumes marketed *(Bcfe)*	**1,067**	1,062	1,127	904	786
Volumes gathered *(Bcf)*	**499**	601	799	963	900

(1) Capital investments include an increase of $43 million for 2016, a decrease of $33 million for 2015, an increase $155 million for 2014, and a decrease of $25 million for 2013, related to the change in accrued expenditures between years. There was no impact to 2017.

(2) Excludes $5 million of legal settlements for 2017.

(3) Excludes $83 million of restructuring and other one-time charges for 2016.

(4) Excludes $3 million of restructuring charges for 2016.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis is the Company's analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the Company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. In many cases you can identify forward-looking statements by words such as "anticipate," "intend," "plan," "project," "estimate," "continue," "potential," "should," "could," "may," "will," "objective," "guidance," "outlook," "effort," "expect," "believe," "predict," "budget," "projection," "goal," "forecast," "target" or similar words. Unless required to do so under the federal securities laws, the Company does not undertake to update, revise or correct any forward-looking statements, whether as a result of new information, future events or otherwise. Readers are cautioned that such forward-looking statements should be read in conjunction with the Company's disclosures under the heading: "Cautionary Statement about Forward-Looking Statements."

OVERVIEW

Background

Southwestern Energy Company (including its subsidiaries, collectively, "we", "our", "us", "the Company" or "Southwestern") is an independent energy company engaged in natural gas, oil and NGL exploration, development and production, which we refer to as "E&P." We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as "Midstream." We conduct most of our businesses through subsidiaries, and we currently operate exclusively in the United States.

Exploration and Production. Our primary business is the exploration for and production of natural gas, oil and NGLs, with our current operations focused on the development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. Our operations in northeast Pennsylvania, which we refer to as "Northeast Appalachia," are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Our operations in West Virginia and southwest Pennsylvania, which we refer to as "Southwest Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. We have smaller holdings in Colorado and Louisiana, along with other areas in which we are testing potential new resources. We also have drilling rigs located in Pennsylvania, West Virginia and Arkansas, and we provide certain oilfield products and services, principally serving our E&P operations.

Midstream. Through our affiliated midstream subsidiaries, we engage in natural gas gathering activities in Arkansas and Louisiana. These activities primarily support our E&P operations and generate revenue from fees associated with the gathering of natural gas. Our marketing activities capture opportunities that arise through the marketing and transportation of natural gas, oil, and NGLs produced in our E&P operations.

In 2017, we focused on our core strategies of capital discipline, operational and technical excellence, margin expansion, strengthening the balance sheet and risk management. Our 2017 capital investment program was fully funded from our operating cash flows, supplemented by the remaining proceeds from our July 2016 equity issuance. We made technological advances in drilling precision and completion optimization that enhanced well productivity and economics, resulting in improved returns. We improved our debt maturity profile, leaving approximately $92 million in bond debt due prior to 2022 with no significant other debt maturities expected before December 2020, and added to our derivative portfolio, protecting approximately 489 Bcf and 201 Bcf of our forecasted 2018 and 2019 natural gas production, respectively, from price volatility through the use of commodity derivatives.

Recent Financial and Operating Results

Significant operating and financial highlights for 2017 include:

Total Company

- Net income attributable to common stock of $816 million, or $1.63 per diluted share, improved substantially from a net loss attributable to common stock of $2,751 million, or ($6.32) per diluted share, in 2016.
- Net cash provided by operating activities of $1,097 million was up 120% from $498 million in 2016.
- Total capital investing of $1,293 million was up 100% from $648 million in 2016.
- We retired the remaining outstanding balance of $316 million of our near-term senior notes due 2017 and 2018.
- We extended the maturities on our debt profile by issuing approximately $1.15 billion in senior notes due 2026 and 2027 and using the net proceeds to repurchase $758 million of our senior notes due 2020 and to repay the outstanding balance of $327 million on our 2015 Term Loan.

Exploration and Production

- E&P segment operating income of $549 million improved substantially from an operating loss of $2,404 million in 2016.
- Year-end reserves of 14,775 Bcfe increased 181% from 5,253 Bcfe at the end of 2016.
- Total net production from our Appalachian Basin of 578 Bcfe was up 16% from 498 Bcfe in 2016.
- Realized NGL prices increased 94% from 2016.

Outlook

In February 2018, we announced several strategic steps to reposition our portfolio, sharpen our focus on our highest return assets, strengthen our balance sheet and enhance financial performance. These initiatives include:

- Actively pursuing strategic alternatives for the Fayetteville Shale E&P and related Midstream gathering assets;
- Identifying and implementing structural, process and organizational changes to further reduce costs; and
- Utilizing funds realized from the foregoing to reduce debt, supplement Appalachian Basin development capital, potentially return capital to shareholders, and for general corporate purposes.

We expect to continue to exercise capital discipline by aligning our 2018 capital investing program with our expected cash flow from operations net of changes in working capital. We will also look for opportunities to maximize margins in each core area of our business and further develop our knowledge of our asset base. We believe that 2018 will continue to be a challenging year for our business due to the commodity price environment and continued uncertainty of natural gas, oil and NGL prices in the United States.

RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand-alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense and income tax expense are discussed on a consolidated basis.

Exploration and Production

(in millions)	For the years ended December 31, 2017	2016	2015
Revenues	**$ 2,086**	$ 1,413	$ 2,074
Impairment of natural gas and oil properties	**–**	2,321	6,950
Operating costs and expenses	**1,537**	1,496 (1)	2,228
Operating income (loss)	**$ 549**	$ (2,404)	$ (7,104)
Gain (loss) on derivatives, settled (2)	**$ (27)**	$ 36	$ 206

(1) Includes $86 million of restructuring and other one-time charges for the year ended December 31, 2016.

(2) Represents the gain (loss) on settled commodity derivatives, and includes $5 million amortization of premiums paid related to certain call options for the year ended December 31, 2017.

Operating Income

- E&P segment operating income for years ended December 31, 2016 and 2015 includes impairments of natural gas and oil properties of $2.3 billion and $7.0 billion, respectively. Excluding the 2016 impairment, our E&P segment operating income increased $632 million for year ended December 31, 2017, compared to the same period in 2016, primarily due to a $673 million increase in revenues, partially offset by a $41 million increase in operating costs.

- Excluding the 2016 and 2015 impairments, our E&P segment operating income increased $71 million for the year ended December 31, 2016, compared to the same period in 2015, as a $661 million decrease in revenues was more than offset by a $732 million decrease in operating costs.

Revenues

The following illustrate the effects on sales revenues associated with changes in commodity prices and production volumes:

(in millions except percentages)	For the years ended December 31, Natural Gas	Oil	NGLs	**Total**
2016 sales revenues	$ 1,252	$ 69	$ 92	**$ 1,413**
Changes associated with prices	507	28	100	**635**
Changes associated with production volumes	16	4	14	**34**
2017 sales revenues	$ 1,775	$ 101	$ 206	**$ 2,082**
Increase from 2016	42%	46%	124%	**47%**

(in millions except percentages)	For the years ended December 31, Natural Gas	Oil	NGLs	**Total**
2015 sales revenues	$ 1,923	$ 76	$ 73	**$ 2,072**
Changes associated with prices	(459) (1)	(5)	11	**(453)**
Changes associated with production volumes	(212)	(2)	8	**(206)**
2016 sales revenues	$ 1,252	$ 69	$ 92	**$ 1,413**
Increase (decrease) from 2015	(35%)	(9%)	26%	**(32%)**

(1) Includes $209 million of gains associated with settled derivatives designated for hedge accounting, which were presented on the 2015 consolidated statements of operations as gas sales. There were no derivatives designated for hedge accounting in 2017 or 2016.

In addition to the sales revenues detailed above, our E&P segment had $4 million of other operating revenues, primarily related to water sales to third-party operators for the year ended December 31, 2017, and $2 million of gathering revenues for the year ended December 31, 2015.

Production Volumes

	For the years ended December 31,				
	2017	Increase/ (Decrease)	2016	Increase/ (Decrease)	2015
Natural Gas *(Bcf)*					
Northeast Appalachia	**395**	13%	350	(3%)	360
Southwest Appalachia	**85**	37%	62	(7%)	67
Fayetteville Shale	**316**	(16%)	375	(19%)	465
Other	**1**	0%	1	(86%)	7
Total	**797**	1%	788	(12%)	899
Oil *(MBbls)*					
Southwest Appalachia	**2,228**	9%	2,041	0%	2,036
Other	**99**	(34%)	151	(34%)	229
Total	**2,327**	6%	2,192	(3%)	2,265
NGL *(MBbls)*					
Southwest Appalachia	**14,193**	15%	12,317	16%	10,640
Other	**52**	(5%)	55	(11%)	62
Total	**14,245**	15%	12,372	16%	10,702
Production volumes by area *(Bcfe)*:					
Northeast Appalachia	**395**	13%	350	(3%)	360
Southwest Appalachia	**183**	24%	148	3%	143
Fayetteville Shale	**316**	(16%)	375	(19%)	465
Other	**3**	50%	2	(75%)	8
Total	**897**	3%	875	(10%)	976

- Production volumes for our E&P segment increased by 22 Bcfe for the year ended December 31, 2017, compared to the same period in 2016, as increased production volumes from Northeast and Southwest Appalachia more than offset decreased natural gas production volumes in the Fayetteville Shale.

- E&P segment production volumes decreased 101 Bcfe for the year ended December 31, 2016, compared to the same period in 2015, as decreased natural gas production volumes in the Fayetteville Shale and Northeast Appalachia more than offset increased production volumes from Southwest Appalachia.

Commodity Prices

The price we expect to receive for our production is a critical factor in determining the capital investments we make to develop our properties. Commodity prices fluctuate due to a variety of factors we cannot control or predict, including increased supplies of natural gas, oil or NGLs due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources. These factors impact supply and demand, which in turn determine the sales prices for our production. In addition to these factors, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. We will continue to evaluate the commodity price environments and adjust the pace of our activity to invest within cash flows in order to maintain appropriate liquidity and financial flexibility.

	For the years ended December 31,				
Average realized price per unit:	**2017**	Increase/ (Decrease)	2016	Increase/ (Decrease)	2015
Natural gas sales, excluding derivatives *(per Mcf)*	**$ 2.23**	40%	$ 1.59	(17%)	$ 1.91
Effect of settled gain (loss) on derivatives *(per Mcf)*	**(0.04)**	(180%)	0.05	(89%)	0.46
Natural gas sales, including derivatives *(per Mcf)*	**$ 2.19**	34%	$ 1.64	(31%)	$ 2.37
Oil sales *(per Bbl)*	**$ 43.12**	38%	$ 31.20	(6%)	$ 33.25
NGL sales, excluding derivatives *(per Bbl)*	**$ 14.46**	94%	$ 7.46	10%	$ 6.80
Effect of settled gain (loss) on derivatives *(per Bbl)*	**0.02**	100%	–	0%	–
NGL sales, including derivatives *(per Bbl)*	**$ 14.48**	94%	$ 7.46	10%	$ 6.80

- Our average price realized for natural gas production, including the effect of derivatives, increased for the year ended December 31, 2017, compared to the same period in 2016, due to a $0.64 per Mcf increase in the average realized price, excluding derivatives, partially offset by a $0.09 per Mcf decrease associated with our settled derivatives.

- The average price realized for our crude oil production increased by $11.92 per Bbl for the year ended December 31, 2017, compared to the same period in 2016. We did not use derivatives to financially protect our 2017, 2016 or 2015 oil production.

- Our average price realized for NGL production, including the effect of derivatives, increased for the year ended December 31, 2017, compared to the same period in 2016, due to a $7.00 per Bbl increase in the average realized price, excluding derivatives, and a $0.02 per Mcf increase associated with our settled derivatives. We did not use derivatives to financially protect our 2016 or 2015 NGL production.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices based on heating content of the gas, locational basis differentials, transportation and fuel charges. Additionally, we receive a sales price for our oil and NGLs at a difference to average monthly West Texas Intermediate settlement and Mont Belvieu NGL composite prices, respectively, due to a number of factors including product quality, composition and types of NGLs sold, locational basis differentials, transportation and fuel charges.

- Excluding the impact of derivatives, the average price received for our natural gas production for the year ended December 31, 2017 of $2.23 per Mcf was approximately $0.88 per Mcf lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation charges. In comparison, the average price received for our natural gas production for the same period in 2016 of $1.59 per Mcf was approximately $0.87 per Mcf lower than the average monthly NYMEX settlement price.

We regularly enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials. We refer you to Item 7A of this Annual Report, Note 4 to the consolidated financial statements, and our derivative risk factor for additional discussion about our derivatives and risk management activities.

- As of December 31, 2017, we have protected basis on approximately 182 Bcf and 70 Bcf of our 2018 and 2019 expected natural gas production, respectively, through physical sales arrangements at a basis differential to NYMEX natural gas price of approximately ($0.25) per MMBtu and ($0.31) per MMBtu for 2018 and 2019, respectively.

- We have also financially protected basis on approximately 44 Bcf and less than 1 Bcf of our 2018 and 2019 expected natural gas production, respectively, through the use of derivatives at a basis differential to NYMEX natural gas price of approximately ($0.48) per MMBtu and ($0.59) per MMBtu for 2018 and 2019, respectively.

- As of December 31, 2017 we have also financially protected 489 Bcf and 201 Bcf of our 2018 and 2019 expected natural gas production, respectively, to limit our exposure to NYMEX price fluctuations.

We refer you to Note 4 of the consolidated financial statements included in this Annual Report for additional details about our derivative instruments.

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Operating Costs and Expenses

	For the years ended December 31,								
(in millions except percentages)		**2017**	Increase/ (Decrease)		2016	Increase/ (Decrease)		2015
Lease operating expenses	$	**809**	6%	$	761	(15%)	$	899
General & administrative expenses		**202**	(1%)		204	(1%)		207
Taxes, other than income taxes		**86**	1%		85	(15%)		100
Restructuring charges		**–**	(100%)		75	100%		–
Full cost pool amortization		**405**	23%		329	(66%)		980
Non-full cost pool DD&A		**35**	(17%)		42	(13%)		48
Gain on sale of assets		**–**	0%		–	(100%)		(6)
Total operating costs	$	**1,537**	3%	$	1,496	(33%)	$	2,228

	For the years ended December 31,							
Average unit costs per Mcfe:		**2017**	Increase/ (Decrease)		2016	Increase/ (Decrease)		2015
Lease operating expenses	$	**0.90**	3%	$	0.87	(5%)	$	0.92
General & administrative expenses	$	**0.22** (1)	0%	$	0.22 (2)	5%	$	0.21
Taxes, other than income taxes	$	**0.10**	0%	$	0.10 (3)	0%	$	0.10
Full cost pool amortization	$	**0.45**	18%	$	0.38	(62%)	$	1.00

(1) Excludes $5 million of legal settlements for the year ended December 31, 2017.

(2) Excludes $83 million of restructuring and other one-time charges for the year ended December 31, 2016.

(3) Excludes $3 million of restructuring charges for the year ended December 31, 2016.

Lease Operating Expenses

- Lease operating expenses per Mcfe increased $0.03 for the year ended December 31, 2017, compared to the same period of 2016, primarily due to increased transportation and gas processing costs, as our production growth shifts toward the Appalachian basin.

- Lease operating expenses per Mcfe decreased $0.05 for the year ended December 31, 2016, compared to the same period of 2015, primarily due to successful renegotiations of our existing gathering and processing rates in our Southwest Appalachia operations and decreased workover activity and contract services.

General and Administrative Expenses

- General and administrative expenses for the year ended December 31, 2017 decreased $2 million, compared to the same period in 2016, as decreased personnel costs were mostly offset by increased legal and information technology charges. The legal charges relate mostly to settlement of litigation and costs of trying a class action in Arkansas.

- On a per Mcfe basis, excluding certain one-time charges of $5 million and $11 million in 2017 and 2016, respectively, general and administrative expenses per Mcfe remained flat for the year ended December 31, 2017, compared to the same period of 2016, as a slight increase in expenses was offset by a 3% increase in production volumes.

- Excluding the one-time charge of $11 million in 2016, general and administrative expenses per Mcfe increased slightly for the year ended December 31, 2016, compared to the same period of 2015, as a $14 million decrease in personnel costs was more than offset by a 10% decrease in production volumes.

Restructuring Charges

- In January 2016, as a result of lower anticipated drilling activity due to a prolonged depressed commodity price environment, we announced a workforce reduction of approximately 1,100 employees. The $75 million one-time restructuring charge consisted of $72 million in general and administrative expenses and $3 million in taxes, other than income taxes.

Taxes, Other than Income Taxes

- Taxes other than income taxes per Mcfe may vary from period to period due to changes in ad valorem and severance taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Full Cost Pool Amortization

- Our full cost pool amortization rate increased $0.07 per Mcfe for the year ended December 31, 2017, as compared to the same period in 2016. The increase in the average amortization rate resulted primarily from the addition of future development costs associated with proved undeveloped reserves recognized as a result of improved commodity prices.

The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling impairments, proceeds from the sale of properties that reduce the full cost pool, and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserve changes.

- Unevaluated costs excluded from amortization were $1.8 billion at December 31, 2017, compared to $2.1 billion and $3.7 billion at December 31, 2016 and 2015, respectively. The unevaluated costs excluded from amortization decreased, as compared to 2016, as the evaluation of previously unevaluated properties totaling $749 million in 2017 was only partially offset by the impact of $461 million of unevaluated capital invested during the same period.

See "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report for additional information regarding our unevaluated costs excluded from amortization.

Midstream

	For the years ended December 31,				
(in millions except percentages)	**2017**	Increase/ (Decrease)	2016	Increase/ (Decrease)	2015
Marketing revenues	**$ 2,867**	31%	$ 2,191	(17%)	$ 2,628
Gas gathering revenues	**331**	(12%)	378	(23%)	491
Marketing purchases	**2,824**	32%	2,145	(16%)	2,566
Operating costs and expenses (1)	**197**	(8%)	215	(13%)	247
Gain on sale of assets, net	**6**	100%	–	(100%)	277
Operating income	**$ 183**	(12%)	$ 209	(64%)	$ 583
Volumes marketed *(Bcfe)*	**1,067**	0%	1,062	(6%)	1,127
Volumes gathered *(Bcf)*	**499**	(17%)	601	(25%)	799
Percent marketed from affiliated E&P operations	**96%**		93%		97%
Percent oil and NGLs marketed from affiliated E&P operations	**63%**		65%		60%

(1) Includes $3 million of restructuring charges for the year ended December 31, 2016.

Operating Income

- Operating income from our Midstream segment decreased $26 million for the year ended December 31, 2017, compared to the same period in 2016, primarily due to a $47 million decrease in gas gathering revenues and a $3 million decrease in marketing margin, partially offset by an $18 million decrease in operating costs and expenses and a $6 million gain on the sale of certain compressor equipment.

- Operating income for the year ended December 31, 2015 includes a $277 million net gain on the sale of our northeastern Pennsylvania and East Texas gathering assets. Excluding the net gain on sale, operating income decreased $97 million for the year ended December 31, 2016, compared to the same period in 2015, primarily due to a $113 million decrease in gas gathering revenues and a $16 million decrease in marketing margin, partially offset by a $32 million decrease in operating costs and expenses.

- The margin generated from marketing activities was $43 million, $46 million and $62 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Margins are driven primarily by volumes marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. Increases and decreases in marketing revenues due to changes in commodity prices and volumes marketed are largely offset by corresponding changes in marketing purchase expenses. We enter into derivative contracts from time to time with respect to our natural gas marketing activities to provide margin protection. For more information about our derivatives and risk management activities, we refer you to Item 7A of Part II of this Annual Report and Note 4 to the consolidated financial statements.

Revenues

- Revenues from our marketing activities increased $676 million for the year ended December 31, 2017, compared to the same period in 2016, primarily due to a 30% increase in the price received for volumes marketed and a 5 Bcfe increase in the volumes marketed.

- For the year ended December 31, 2016, revenues from our marketing activities decreased $437 million, compared to the same period in 2015, primarily due to a 12% decrease in the price received for volumes marketed and a 65 Bcfe decrease in volumes marketed.

- The consecutive decreases in gas gathering revenues for the years ended December 31, 2017 and 2016 primarily resulted from decreasing volumes gathered in the Fayetteville Shale.

Operating Costs and Expenses

- The consecutive decreases in operating costs and expenses for the years ended December 31, 2017 and 2016, respectively, primarily resulted from reduced compression and personnel costs due to lower activity levels as a result of decreasing volumes gathered in the Fayetteville Shale.

Restructuring Charges

In January 2016, we announced a 40% workforce reduction, which was substantially concluded by the end of March 2016. In April 2016, we also partially restructured executive management. Affected employees were offered a severance package that included a one-time cash payment depending on length of service and, if applicable, accelerated vesting of outstanding stock-based equity awards. As a result of the workforce reduction and executive management restructuring, we recognized restructuring charges of $78 million for the year ended December 31, 2016.

Interest Expense

	For the years ended December 31,				
(in millions except percentages)	**2017**	Increase/ (Decrease)	2016	Increase/ (Decrease)	2015
Gross interest expense:					
Senior notes	**$ 177**	(3%)	$ 183	1%	$ 181
Credit arrangements	**62**	44%	43	126%	19
Amortization of debt costs	**9**	(36%)	14	(77%)	60
Total gross interest expense	**248**	3%	240	(8%)	260
Less: capitalization	**(113)**	(26%)	(152)	(25%)	(204)
Net interest expense	**$ 135**	53%	$ 88	57%	$ 56

- Interest expense related to our senior notes decreased for the year ended December 31, 2017, as compared to the same period in 2016, as a decrease in interest expense related to the gradual redemption of our 7.50% Senior Notes due in February 2018, which began in July 2016 and completed in May 2017, was only partially offset by increased interest expense which resulted from the issuance of new senior notes in September 2017.

- Interest expense related to our credit arrangements increased for the years ended December 31, 2017 and 2016, as compared to the same periods in 2016 and 2015, respectively, due to increased outstanding borrowings and higher interest rates.

- Amortization of debt costs for the year ended December 31, 2015 include a $47 million charge for unamortized fees associated with the repayment of our short-term bridge facility in the first quarter of 2015, as this temporary facility was replaced with permanent financing.

- The decreases in capitalized interest for the years ended December 31, 2017 and 2016, as compared to the same periods in 2016 and 2015, respectively, were primarily due to the continued evaluation of a portion of our Southwest Appalachia assets.

- The increase in interest expense related to our senior notes for the year ended December 31, 2016, as compared to the same period in 2015, was primarily due to an increase in our cost of debt of 175 basis points that became effective in July 2016 as a result of downgrades by Moody's and S&P on our 2018, 2020 and 2025 Senior Notes.

Gain (Loss) on Derivatives

	For the years ended December 31,		
(in millions)	**2017**	2016	2015
Gain (loss) on unsettled derivatives	**$ 451**	$ (373)	$ (155)
Gain (loss) on settled derivatives [(1)]	**(29)**	34	202
Total gain (loss) on derivatives [(1)]	**$ 422**	$ (339)	$ 47

(1) Includes $5 million amortization of premiums paid related to certain call options for the year ended December 31, 2017, which is included in gain (loss) on derivatives on the consolidated statement of operations.

We refer you to Note 4 to the consolidated financial statements included in the Annual Report for additional details about our gain (loss) on derivatives.

Loss on Early Extinguishment of Debt

- In September 2017, we used the net proceeds of approximately $1.1 billion from our September 2017 senior notes offering to repurchase approximately $758 million of our 2020 Senior Notes and to repay the remaining $327 million principal amount outstanding of our 2015 Term Loan. We recognized a loss of $59 million for the redemption of these senior notes which included $53 million of premiums paid.

- In the first half of 2017, we redeemed the remaining $276 million principal amount outstanding of our 2018 Senior Notes, recognizing a loss of $11 million.

- During the third quarter of 2016, we used proceeds from our $1,247 million July 2016 equity offering to purchase and retire $700 million of our outstanding senior notes due in the first quarter of 2018 and retire $375 million of our $750 million term loan entered into in November 2015. We recognized a loss of $51 million for the redemption of these senior notes, which included $50 million of premiums paid.

Income Taxes

	For the years ended December 31,		
(in millions except percentages)	**2017**	2016	2015
Income tax expense (benefit)	**$ (93)**	$ (29)	$ (2,005)
Effective tax rate	**(10%)**	1%	31%

- The income tax benefits recognized for the year ended December 31, 2017 primarily resulted from changes in federal tax legislation enacted under the Tax Cuts and Jobs Act (Tax Reform) which will allow us to recover certain alternative minimum tax credit carryovers, along with the expiration of a portion of our uncertain tax provision.

- Our low effective tax rate is the result of our recognition of a valuation allowance that reduced the deferred tax asset primarily related to our current net operating loss carryforward, as well as changes to the deferred tax rate enacted under the recent Tax Reform. A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized.

We refer you to Note 9 to the consolidated financial statements for additional discussion about our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on funds generated from our operations, our cash and cash equivalents balance, our $809 million revolving credit facilities and capital markets as our primary sources of liquidity. Although we have financial flexibility with our cash balance and the ability to draw on our revolving credit facilities as necessary, we continue to be committed to our capital discipline strategy of investing within our cash flow from operations net of changes in working capital, supplemented in 2017 by the remaining proceeds from the July 2016 equity issuance.

Our cash flow from operating activities is highly dependent upon the sales prices that we receive for our natural gas and liquids production. Natural gas, oil and NGL prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. The sales price we receive for our production is also influenced by our commodity hedging activities. See "Risk Factors" in Item 1A, "Quantitative and Qualitative Disclosures about Market Risks" in Item 7A and Note 4, "Derivatives and Risk Management" in the consolidated financial statements for further details.

Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. At December 31, 2017, we had NYMEX price derivatives in place on 489 Bcf and 201 Bcf on our targeted 2018 and 2019 natural gas production, respectively, for protection against a decrease in natural gas prices. We also had commodity derivatives in place on 183 MBbls of both our targeted 2018 ethane and propane production.

Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to settle the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Our short-term cash flows are also dependent on the timely collection of receivables from our customers and joint interest partners. We actively manage this risk through credit management activities and, through the date of this filing, have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and joint interest partners could adversely impact our cash flows.

Due to these above factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we expect to adjust our discretionary uses of cash depending upon available cash flow. Further, we may from time to time seek to retire, rearrange or amend some or all of our outstanding debt or debt agreements through cash purchases, and/or exchanges, open market purchases, privately negotiated transactions, tender offers or otherwise. Such transactions, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Credit Arrangements and Financing Activities

We have taken substantial steps in managing our debt maturities and liquidity in 2017. These steps, discussed in further detail below, had the effect of extending maturities on total debt outstanding by reducing the amount of debt, net of cash and cash equivalents, coming due prior to 2022 from $1,261 million as of December 31, 2016 to $367 million as of December 31, 2017.

- In November 2017, we solicited and received consent to amend certain restrictive covenants contained in the indentures governing our 2022 Notes and 2025 Notes. These amendments conform certain covenants of the 2022 Notes and 2025 Notes to all other series of senior notes.
- In October 2017, we retired $40 million principal amount outstanding of our 2017 Senior Notes.
- In September 2017, we completed a public offering of $650 million aggregate principal amount of our 7.50% Senior Notes due 2026 and $500 million aggregate principal amount of our 7.75% Senior Notes due 2027, with net proceeds from the offering totaling approximately $1.1 billion after underwriting discounts and offering expenses.
- The proceeds from the September 2017 offering were used to repurchase $758 million of our 4.05% Senior Notes due 2020 and to repay the remaining $327 million principal amount outstanding of the term loan we borrowed in November 2015.

- Also in September 2017, we entered into Amendment No. 1 to the credit agreement we entered into in June 2016 providing a $1,191 million secured term loan and $743 million unsecured revolving facility. This amendment provides greater flexibility to our minimum liquidity covenant and allows us to retain the first $500 million of net cash proceeds from asset sales that would have otherwise been required to be used for further debt reduction.

- During the first half of 2017, we redeemed the remaining $276 million principal amount outstanding of our 2018 Senior Notes.

The revolving credit facility component of our June 2016 credit agreement provides borrowing capacity of $743 million and matures in December 2020. The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least $765 million of our senior notes due in January 2020. As of December 31, 2017, we have repurchased and refinanced approximately $758 million of our 4.05% Senior Notes due 2020. The revolving credit facility we entered into in December 2013, as reduced in June 2016, provides borrowing capacity of $66 million and matures in December 2018. As of December 31, 2017, there were no borrowings under either revolving credit facility; however, there was $323 million in letters of credit outstanding against the 2016 revolving credit facility.

As of December 31, 2017, we were in compliance with all of the covenants of the term loan and revolving credit facilities. Although we do not anticipate any violations of the financial covenants, our ability to comply with these covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and liquids. We refer you to Note 7 of the consolidated financial statements included in this Annual Report for additional discussion of the covenant requirements of our term loan and revolving credit facilities.

At February 27, 2018, we had a long-term issuer credit rating of Ba3 by Moody's, a long-term debt rating of BB- by S&P and a long-term issuer default rating of BB by Fitch Ratings. Any downgrades in our public debt ratings by Moody's or S&P could increase our cost of funds and decrease our liquidity under our revolving credit facilities.

The credit status of the financial institutions participating in our revolving credit facilities could adversely impact our ability to borrow funds under the revolving credit facilities. Although we believe all of the lenders under the facilities have the ability to provide funds, we cannot predict whether each will be able to meet their obligation to us. We refer you to Note 7 of the consolidated financial statements included in this Annual Report for additional discussion of our credit facilities.

Cash Flows

	For the years ended December 31,		
(in millions)	**2017**	2016	2015
Net cash provided by operating activities	**$ 1,097**	$ 498	$ 1,580
Net cash (used in) investing activities	**(1,252)**	(162)	(1,638)
Net cash provided by (used in) financing activities	**(352)**	1,072	20

Cash Flow from Operations

- Net cash provided by operating activities increased 120% or $599 million for the year ended December 31, 2017, compared to the same period in 2016, primarily due to an increase in revenues resulting from increased realized commodity prices and a 3% increase in production volumes.

- For the year ended December 31, 2016, net cash provided by operating activities decreased 68% or $1,082 million, compared to the same period in 2015, primarily due to a decrease in revenues resulting from a 31% decrease in realized natural gas prices and a 10% decrease in production volumes.

- Net cash generated from operating activities provided 85% of our cash requirements for capital investments for the year ended December 31, 2017, compared to net cash from operating activities providing 77% and 63% of our cash requirements for capital investments for the same periods in 2016 and 2015, respectively, reflecting our commitment to our capital discipline strategy of investing within our cash flow from operations net of changes in working capital, supplemented by the remaining proceeds from the 2016 equity issuance and asset sales.

Cash Flow from Investing Activities

(in millions)	For the years ended December 31, **2017**	2016	2015
Cash flows from investing activities:			
Additions to properties and equipment	**$ 1,268**	$ 593	$ 2,377
Adjustments for capital investments:			
Changes in capital accruals	**–**	43	(33)
Other non-cash adjustments to properties and equipment	**25**	12	93
Total capital investing	**$ 1,293**	$ 648	$ 2,437

(in millions except percentages)	For the years ended December 31, **2017**	Increase/ (Decrease)	2016	Increase/ (Decrease)	2015
Capital investing:					
E&P [(1)]	**1,248**		623		1,725
Acquisitions	**–**		–		642
Midstream Services	**32**		21		58
Other	**13**		4		12
Total capital investing	**$ 1,293**	100%	$ 648	(74%)	$ 2,437

(1) Includes $212 million, $239 million and $379 million of capitalized interest and internal costs for the years ended December 31, 2017, 2016 and 2015, respectively. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties.

- Total E&P capital investing increased $625 million for the year ended December 31, 2017, compared to the same period in 2016, as a $652 million increase in direct E&P capital investing was only partially offset by a $27 million decrease in capitalized interest and internal costs. The significant increase in 2017 capital investing resulted from our decision to suspend drilling activity in the first half of 2016 due to an unfavorable commodity price environment. We began increasing activity in the second half of 2016.

- For the year ended December 31, 2016, total E&P capital investing decreased $1,102 million, compared to the same period in 2015 (excluding 2015 acquisitions), due to a $962 million decrease in direct E&P capital investing and a $140 million decrease in capitalized interest and internal costs. The significant decrease was the result of suspending drilling activity in the first half of 2016 due to an unfavorable commodity price environment.

- The increase in E&P capital investments for the year ended December 31, 2017, as compared to the same period in 2016, reflects our operational flexibility in light of current and expected economic conditions, as we adjusted our activities based on our anticipated cash flows from operation net of changes in working capital.

- The decreases in capitalized interest for the years ended December 31, 2017 and 2016, as compared to the same periods in 2016 and 2015, respectively, were primarily due to the continued evaluation of a portion of our Southwest Appalachia assets acquired in December 2014.

- Midstream capital investing increased $11 million for the year ended December 31, 2017, compared to the same period in 2016, related primarily to the purchase of several of our leased compressors during 2017 which were subsequently sold to third parties for a net gain of $6 million.

- For the year ended December 31, 2016, Midstream capital investing decreased $37 million, compared to the same period in 2015, primarily due to reduced activity in the Fayetteville Shale.

Actual capital expenditure levels may vary significantly from period to period due to many factors, including drilling results, natural gas, oil and NGL prices, industry conditions, the prices and availability of goods and services, and the extent to which properties are acquired or non-strategic assets are sold.

Cash Flow from Financing Activities

(in millions except percentages)	For the years ended December 31, 2017	2016	Increase/ (Decrease)
Short-term debt	**$ –**	$ 41	$ (41)
Long-term debt	**4,391**	4,612	(221)
Total debt	**$ 4,391**	$ 4,653	$ (262)
Equity	**$ 1,979**	$ 917	$ 1,062
Total debt to capitalization ratio (1)	**69%**	84%	(15%)
Total debt	**$ 4,391**	$ 4,653	$ (262)
Less: Cash and cash equivalents	**916**	1,423	(507)
Debt, net of cash and cash equivalents	**$ 3,475**	$ 3,230	$ 245

(1) Debt, net of cash and cash equivalents is a non-GAAP financial measure of a company's ability to repay its debts if they were all due today.

- Net cash used in financing activities for the year ended December 31, 2017 was $352 million, compared to net cash provided by financing activities of $1,072 million for the same period in 2016. The net cash provided by financing activities in 2016 resulted primarily from our fully-drawn 2016 Term Loan.

- In October 2017, we retired $40 million principal amount outstanding of our 2017 Senior Notes.

- In September 2017, we completed a public offering of $650 million aggregate principal amount of our 7.50% Senior Notes due 2026 and $500 million aggregate principal amount of our 7.75% Senior Notes due 2027, with net proceeds from the offering totaling approximately $1.1 billion, after approximately $17 million in offering expenses.

- The proceeds from the September 2017 offering were used to repay $758 million of our 4.05% Senior Notes due 2020 and the remaining $327 million principal amount outstanding of our 2015 Term Loan. We recognized a loss on early extinguishment of debt of $59 million.

- In the first half of 2017, we redeemed $276 million principal amount outstanding of our 2018 Senior Notes. We recognized a loss on early extinguishment of debt of $11 million.

We refer you to Note 7 of the consolidated financial statements included in this Annual Report for additional discussion of our outstanding debt and credit facilities.

Working Capital

- We had positive working capital of $729 million at December 31, 2017 primarily due to $916 million of cash and cash equivalents resulting from our fully-drawn 2016 term loan.

- At December 31, 2016, we had positive working capital of $808 million primarily due to $1.4 billion of cash and cash equivalents resulting from our fully-drawn 2016 term loan, our July 2016 equity offering and proceeds from the September 2016 sale of our West Virginia acreage.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2017, our material off-balance sheet arrangements and transactions include operating lease arrangements and $323 million in letters of credit outstanding against our 2016 revolving credit facility. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. For more information regarding off-balance sheet arrangements, we refer you to "Contractual Obligations and Contingent Liabilities and Commitments" below for more information on our operating leases.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations as of December 31, 2017, were as follows:

Contractual Obligations:

	Payments Due by Period					
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
	(in millions)					
Transportation charges (1)	**$ 9,171**	$ 702	$ 1,565	$ 1,253	$ 1,742	$ 3,909
Debt	**4,433**	–	1,283	1,000	1,000	1,150
Interest on debt (2)	**1,646**	250	494	370	430	102
Operating leases (3)	**213**	66	105	31	7	4
Compression services (4)	**15**	12	3	–	–	–
Operating agreements	**91**	90	1	–	–	–
Purchase obligations	**30**	30	–	–	–	–
Other obligations (5)	**21**	10	11	–	–	–
	$ 15,620	$ 1,160	$ 3,462	$ 2,654	$ 3,179	$ 5,165

(1) As of December 31, 2017, we had commitments for demand and similar charges under firm transport and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems. Of the total $9.2 billion, $3.0 billion related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. For further information, we refer you to “Operational Commitments and Contingencies” in Note 8 to the consolidated financial statements.

(2) Interest payments on our senior notes were calculated utilizing the fixed rates associated with our fixed rate notes outstanding at December 31, 2017. Interest payments on the term loan facility were calculated by assuming that the December 31, 2017 outstanding balance of $1,191 million will be outstanding through the December 2020 maturity date. A constant rate of 3.98%, the rate as of December 31, 2017, was assumed for the December 2020 term loan facility. All interest rates were based on our credit ratings as of December 31, 2017.

(3) Operating leases include costs for compressors, drilling rigs, pressure pumping equipment, aircraft, office space and other equipment under non-cancelable operating leases expiring through 2027.

(4) As of December 31, 2017, our Midstream segment had commitments of approximately $12 million and our E&P segment had commitments of approximately $3 million for compression services associated primarily with our Fayetteville and Southwest Appalachia divisions.

(5) Our other significant contractual obligations include approximately $14 million for various information technology support and data subscription agreements.

Liabilities relating to uncertain tax positions are excluded from the table above as there is a high degree of uncertainty regarding the timing of future cash outflows related to such liabilities. Also excluded from the table above are future contributions to the pension and postretirement benefit plans. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 11 to the consolidated financial statements and “Critical Accounting Policies and Estimates” below for additional information.

We refer you to Note 7 to the consolidated financial statements for a discussion of the terms of our debt.

We are subject to various litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties, employment matters, traffic incidents and pollution, contamination or nuisance. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. Management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows, although it is possible that adverse outcomes could have a material adverse effect on our results of operations or cash flows for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management’s view may change in the future.

We are also subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position or results of operations.

For further information, we refer you to “Litigation” and “Environmental Risk” in Note 8 to the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The discussion and analysis of financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. We evaluate our estimates on an on-going basis, based on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following describes significant judgments and estimates used in the preparation of our consolidated financial statements.

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and related capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2017, we had a total of $1,817 million of costs excluded from our amortization base, all of which related to our properties in the United States. Inclusion of some or all of these costs in our properties in the United States in the future, without adding any associated reserves, could result in ceiling test impairments.

At December 31, 2017, the ceiling value of our reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.98 per MMBtu, for West Texas Intermediate oil of $47.79 per barrel and NGLs of $14.41 per barrel, adjusted for market differentials. The net book value of our natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2017. Although no ceiling test impairment was recorded in 2017, future decreases in commodity prices, increases in costs and/or changes in the balance of costs excluded from amortization and other factors may result in impairments to our natural gas and oil properties.

The net book value of our United States and Canada natural gas and oil properties exceeded the ceiling by approximately $641 million (net of tax) at March 31, 2016, $297 million (net of tax) at June 30, 2016 and $506 million (net of tax) at September 30, 2016, resulting in non-cash ceiling test impairments in each of those quarters ended those dates. We had no hedge positions that were designated for hedge accounting as of March 31, 2016, June 30, 2016 and September 30, 2016. Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.48 per MMBtu, West Texas Intermediate oil of $39.25 per barrel and NGLs of $6.74 per barrel, adjusted for market differentials, the net book value of our United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2016. We had no derivative positions that were designated for hedge accounting as of December 31, 2016.

The net book value of our United States natural gas and oil properties exceeded the ceiling by $944 million (net of tax) at June 30, 2015 and $1,746 million (net of tax) at September 30, 2015 and resulted in non-cash ceiling test impairments in the quarters ended those dates. Cash flow hedges of natural gas production in place increased the ceiling amount by approximately $60 million and $40 million as of June 30, 2015 and September 30, 2015, respectively. Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.59 per MMBtu, West Texas Intermediate oil of $46.79 per barrel and NGLs of $6.82 per barrel, adjusted for market differentials, the net book value of our United States natural gas and oil properties exceeded the ceiling by $1,586 million (net of tax) at December 31, 2015 and resulted in a non-cash ceiling test impairment. No cash flow hedges were in place as of December 31, 2015.

A decline in natural gas, oil and NGL prices used to calculate the discounted future net revenues of our reserves affects both the present value of cash flows and the quantity of reserves. In the past, nearly all of our reserve base was natural gas; therefore changes in oil and NGL prices used did not have as significant an impact as natural gas prices on cash flows and reserve quantities. Our reserve base as of December 31, 2017, however, was approximately 75% natural gas. Our standardized measure and reserve quantities as of December 31, 2017, were $5.6 billion and 14.8 Tcfe, respectively.

Natural gas, oil and NGL reserves cannot be measured exactly. Our estimate of natural gas, oil and NGL reserves requires extensive judgments of reservoir engineering data and projections of cost that will be incurred in developing and producing reserves and is generally less precise than other estimates made in connection with financial disclosures. Our reservoir engineers prepare our reserve estimates under the supervision of our management. Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team to which the property is assigned. The reservoir engineering and financial data included in these estimates are reviewed by senior engineers, who are not part of the asset management teams, and by our Reservoir Supervisor – Reserves, who is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Reservoir Supervisor – Reserves has more than 31 years of experience in petroleum engineering, including the estimation of oil and natural gas reserves, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining us in 2009, our Reservoir Supervisor – Reserves served in various reservoir engineering roles for Citation Oil & Gas Corporation, Mitchell Energy & Development Corporation, White Stone Energy and H.J. Gruy & Associates and is a member of the Society of Petroleum Engineers and Society of Petroleum Evaluation Engineers and is a Licensed Professional Engineer in the state of Texas. He reports to our Senior Vice President – SWN Advance, who has more than 23 years of experience in petroleum engineering including the estimation of natural gas, oil and NGL reserves in multiple basins in the United States, and holds a Bachelor of Science in Petroleum Engineering and a Master of Business Administration. Prior to joining Southwestern in 2014, our Senior Vice President – SWN Advance served in various engineering and leadership roles for Quantum Resource Management, Anadarko Petroleum Company, Howell Petroleum and Meridian Oil/Burlington Resources and is a member of the Society of Petroleum Engineers and IPSS.

We engage NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates as discussed in more detail below. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the two technical persons primarily responsible for auditing our proved reserves estimates (1) have over 36 years and over 15 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 26 years and over 15 years of experience in the estimation and evaluation of reserves, respectively; (3) each has a college degree; (4) each is a Licensed Professional Geoscientist in the State of Texas or a Licensed Professional Engineer in the State of Texas; (5) each meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; and (6) each is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. The financial data included in the reserve estimates is also separately reviewed by our accounting staff. Our proved reserves estimates, as internally reviewed and audited by NSAI, are submitted for review and approval to our Chief Executive Officer. Finally, upon his approval, NSAI reports the results of its reserve audit to the Board of Directors, with whom final authority over the estimates of our proved reserves rests. A copy of NSAI's report has been filed as Exhibit 99.1 to this Annual Report.

Proved developed reserves generally have a higher degree of accuracy in this estimation process, when compared to proved undeveloped and proved non-producing reserves, as production history and pressure data over time is available for the majority of our proved developed properties. Proved developed reserves accounted for 54% of our total reserve base as of December 31, 2017. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We refer you to "Our proved natural gas, oil and NGL reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A, "Risk Factors," of Part I of this Annual Report for a more detailed discussion of these uncertainties, risks and other factors.

In conducting its audit, the engineers and geologists of NSAI study our major properties in detail and independently develop reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of major properties that account for approximately 99% of the present worth of the company's total proved reserves. NSAI's audit process consists of sorting all fields by descending present value order and selecting the fields from highest value to descending value until the selected fields account for more than 80% of the present worth of our reserves. The fields included in approximately the top 99% present value as of December 31, 2017, accounted for approximately 99% of our total proved reserves and approximately 100% of our proved undeveloped reserves. In the conduct of its audit, NSAI did not independently verify the data we provided to them with respect to ownership interests, natural gas, oil and NGL production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. NSAI has advised us that if, in the course of its audit, something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved any questions relating thereto or had independently verified such information or data. On February 2, 2018, NSAI issued its audit opinion as to the reasonableness of our reserve estimates for the year-ended December 31, 2017 stating that our estimated proved natural gas, oil and NGL reserves are, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Derivatives and Risk Management

We use fixed price swap agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of certain commodities and interest rates. Our policies prohibit speculation with derivatives and limit agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. In 2017, 2016, and 2015 we financially protected 70%, 28% and 27% of our natural gas production, respectively, with derivatives. The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas. However, the market price risk is generally offset by the gain or loss recognized upon the related natural gas transaction that is financially protected.

All derivatives are recognized in the balance sheet as either an asset or a liability as measured at fair value other than transactions for which the normal purchase/normal sale exception is applied. Certain criteria must be satisfied for derivative financial instruments to be designated for hedge accounting. Accounting guidance for qualifying hedges allows an unsettled derivative's unrealized gains and losses to be recorded in either earnings or as a component of other comprehensive income until settled. In the period of settlement, we recognize the gains and losses from these qualifying hedges in gas sales revenues. The ineffective portion of those fixed price swaps was recognized in earnings. Gains and losses on derivatives that are not designated for hedge accounting treatment, or that do not meet hedge accounting requirements, are recorded as a component of gain (loss) on derivatives on the consolidated statements of operations. Accordingly, the gain (loss) on derivatives component of the statement of operations reflects the gains and losses on both settled and unsettled derivatives. We calculate gains and losses on settled derivatives as the summation of gains and losses on positions which have settled within the reporting period.

As of December 31, 2017, none of our derivative contracts were designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated for hedge accounting treatment are recorded in gain (loss) on derivatives. We recorded gains on derivatives of $232 million related to fixed price swaps, $62 million related to sold call options, $136 million related to three-way costless collars, $52 million related to two-way costless collars, $2 million related to purchased call options and $3 million related to interest rate swaps. These gains were partially offset by a loss on derivatives of $36 million related to basis swaps.

Future market price volatility could create significant changes to the derivative positions recorded in our consolidated financial statements. We refer you to "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A of Part II of this Annual Report for additional information regarding our hedging activities.

Pension and Other Postretirement Benefits

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation (see Note 11 to the consolidated financial statements for further discussion and disclosures regarding these benefit plans). Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For the December 31, 2017 benefit obligation and periodic benefit cost to be recorded in 2018, the discount rate assumed is 3.75% and 4.20%, respectively. This compares to a discount rate of 4.20% for both the benefit obligation and periodic benefit cost recorded in 2017. For the 2018 periodic benefit cost, the expected return assumed remains 7.00%, from 2017.

Using the assumed rates discussed above, we recorded total benefit cost of $12 million in 2017 related to our pension and other postretirement benefit plans. Due to the significance of the discount rate and expected long-term rate of return, the following sensitivity analysis demonstrates the effect that a 0.5% change in those assumptions would have had on our 2017 pension expense:

	Increase (Decrease) of Annual Pension Expense	
(in millions)	0.5% Increase	0.5% Decrease
Discount rate	$ (1)	$ 1
Expected long-term rate of return	$ –	$ –

As of December 31, 2017, we recognized a liability of $59 million, compared to $49 million at December 31, 2016, related to our pension and other postretirement benefit plans. During 2017, we also made cash payments totaling $15 million to fund our pension and other postretirement benefit plans.

Asset Retirement Obligations

We must plug and abandon our wells when they no longer are producing. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The recognition of asset retirement obligations requires management to make assumptions that include estimated plugging and abandonment costs, timing of settlements, inflation rates and discount rates, all of which are subject to change.

Stock-Based Compensation

We account for stock-based compensation transactions using a fair value method and recognize an amount equal to the fair value of the stock options and stock-based payment cost in either the consolidated statement of operations or capitalize the cost into natural gas and oil properties or gathering systems included in property and equipment. Costs are capitalized when they are directly related to the acquisition, exploration and development activities of our natural gas and oil properties or directly related to the construction of our gathering systems. We use models to determine fair value of stock-based compensation, which requires significant judgment with respect to forfeitures, volatility and other factors. If any of the assumptions change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period.

New Accounting Standards

Refer to Note 1 to the consolidated financial statements of this Annual Report for further discussion of our significant accounting policies and for discussion of accounting standards that have been implemented in this report, along with a discussion of relevant accounting standards that are pending adoption.

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Annual Report on Form 10-K identified by words such as "anticipate," "intend," "plan," "project," "estimate," "continue," "potential," "should," "could," "may," "will," "objective," "guidance," "outlook," "effort," "expect," "believe," "predict," "budget," "projection," "goal," "forecast," "target" or similar words.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for natural gas, oil and NGLs (including regional basis differentials);
- our ability to fund our planned capital investments;
- a change in our credit rating;
- the extent to which lower commodity prices impact our ability to service or refinance our existing debt;
- the impact of volatility in the financial markets or other global economic factors;
- difficulties in appropriately allocating capital and resources among our strategic opportunities;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- our ability to maintain leases that may expire if production is not established or profitably maintained;
- our ability to realize the expected benefits from recent acquisitions;
- our ability to transport our production to the most favorable markets or at all;
- availability and costs of personnel and of products and services provided by third parties;
- the impact of government regulation, including the ability to obtain and maintain permits, any increase in severance or similar taxes, and legislation relating to hydraulic fracturing, climate and over-the-counter derivatives;
- the impact of the adverse outcome of any material litigation against us;
- the effects of weather;
- increased competition and regulation;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the SEC.

Should one or more of the risks or uncertainties described above or elsewhere in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as service costs and credit risk concentrations. We use fixed price swap agreements, fixed price options, basis swaps and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risks is also overseen by our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our exposure to concentrations of credit risk consists primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our purchasers and their dispersion across geographic areas. However, for the year ended December 31, 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.3% of total natural gas, oil and NGL sales. A default on this account could have a material impact on the Company, but we do not believe that there is a material risk of an event of default. During the years ended December 31, 2016 and 2015, no single third-party purchaser accounted for 10% or more of our consolidated revenues. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

As of December 31, 2017, we had approximately $3.2 billion of outstanding senior notes with a weighted average interest rate of 6.19%, and $1.2 billion of term loan facility debt with a variable interest rate of 3.98%. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates.

	Expected Maturity Date						
	2017	2018	2019	2020	2021	Thereafter	Total
Fixed Rate payments [1] *(in millions)*	$ –	$ –	$ –	$ 92	$ –	$ 3,150	$ 3,242
Weighted Average Interest Rate	– %	– %	– %	5.80%	– %	6.21%	6.19%
Variable Rate Payments [1] *(in millions)*	$ –	$ –	$ –	$ 1,191 [2]	$ –	$ –	$ 1,191
Weighted Average Interest Rate	– %	– %	– %	3.98%	– %	– %	3.98%

(1) Excludes unamortized debt issuance costs and debt discounts.

(2) The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least $765 million of our 2020 Senior Notes. As of December 31, 2017, we have redeemed and refinanced $758 million principal amount of the 2020 senior notes.

Commodities Risk

We use over-the-counter fixed price swap agreements and options to protect sales of our production against the inherent risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps) and transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps).

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas that is financially protected. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major banks and integrated energy companies that management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, we cannot be certain that we will not experience such losses in the future. We refer you to Note 4 of the consolidated financial statements included in this Annual Report for additional details about our derivative instruments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control Over Financial Reporting

It is the responsibility of the management of Southwestern Energy Company to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, utilizing the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control—Integrated Framework (2013).*

Based on this evaluation, management has concluded the Company's internal control over financial reporting was effective as of December 31, 2017.

The effectiveness of our internal control over financial reporting as of December 31, 2017 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Southwestern Energy Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Southwestern Energy Company and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

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, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

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 Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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/PRICEWATERHOUSECOOPERS LLP

Houston, TX
March 1, 2018

We have served as the Company's auditor since 2002.

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the years ended December 31,		
	2017	2016	2015
	(in millions, except share/per share amounts)		
Operating Revenues:			
Gas sales	**$ 1,793**	$ 1,273	$ 1,946
Oil sales	**102**	69	76
NGL sales	**206**	92	73
Marketing	**972**	864	863
Gas gathering	**126**	138	175
Other	**4**	–	–
	3,203	2,436	3,133
Operating Costs and Expenses:			
Marketing purchases	**976**	864	852
Operating expenses	**671**	592	689
General and administrative expenses	**233**	247	246
Restructuring charges	**–**	78	–
Depreciation, depletion and amortization	**504**	436	1,091
Impairment of natural gas and oil properties	**–**	2,321	6,950
Gain on sale of assets, net	**(6)**	–	(283)
Taxes, other than income taxes	**94**	93	110
	2,472	4,631	9,655
Operating Income (Loss)	**731**	(2,195)	(6,522)
Interest Expense:			
Interest on debt	**239**	226	200
Other interest charges	**9**	14	60
Interest capitalized	**(113)**	(152)	(204)
	135	88	56
Gain (Loss) on Derivatives	**422**	(339)	47
Loss on Early Extinguishment of Debt	**(70)**	(51)	–
Other Income (Loss), Net	**5**	1	(30)
Income (Loss) Before Income Taxes	**953**	(2,672)	(6,561)
Benefit for Income Taxes:			
Current	**(22)**	(7)	(2)
Deferred	**(71)**	(22)	(2,003)
	(93)	(29)	(2,005)
Net Income (Loss)	**$ 1,046**	$ (2,643)	$ (4,556)
Mandatory convertible preferred stock dividend	**108**	108	106
Participating securities – mandatory convertible preferred stock	**123**	–	–
Net Income (Loss) Attributable to Common Stock	**$ 815**	$ (2,751)	$ (4,662)
Earnings (Loss) Per Common Share:			
Basic	**$ 1.64**	$ (6.32)	$ (12.25)
Diluted	**$ 1.63**	$ (6.32)	$ (12.25)
Weighted Average Common Shares Outstanding:			
Basic	**498,264,321**	435,337,402	380,521,039
Diluted	**500,804,297**	435,337,402	380,521,039

The accompanying notes are an integral part of these consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	For the years ended December 31,		
	2017 (1)	2016	2015
		(in millions)	
Net income (loss)	**$ 1,046**	$ (2,643)	$ (4,556)
Change in derivatives:			
Settlements (2)	**–**	–	(128)
Ineffectiveness	**–**	–	1
Change in fair value of derivative instruments (3)	**–**	–	29
Total change in derivatives	**–**	–	(98)
Change in value of pension and other postretirement liabilities:			
Amortization of prior service cost and net loss included in net periodic pension cost (4)	**2**	13	2
Net loss incurred in period (5)	**(13)**	(7)	(3)
Total change in value of pension and postretirement liabilities	**(11)**	6	(1)
Change in currency translation adjustment	**6**	3	(11)
Comprehensive income (loss)	**$ 1,041**	$ (2,634)	$ (4,666)

(1) In 2017, deferred tax activity incurred in other comprehensive income was offset by a valuation allowance.

(2) Net of ($81) million in taxes for the year ended December 31, 2015.

(3) Net of $16 million in taxes for the year ended December 31, 2015.

(4) Net of $8 million in taxes for the year ended December 31, 2016.

(5) Net of ($4) million in taxes for the year ended December 31, 2016.

The accompanying notes are an integral part of these consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

		December 31, 2017		December 31, 2016
ASSETS		*(in millions)*		
Current assets:				
Cash and cash equivalents	**$**	**916**	$	1,423
Accounts receivable, net		**428**		363
Derivative assets		**130**		51
Other current assets		**35**		35
Total current assets		**1,509**		1,872
Natural gas and oil properties, using the full cost method, including $1,817 million as of December 31, 2017 and $2,105 million as of December 31, 2016 excluded from amortization		**23,890**		22,653
Gathering systems		**1,315**		1,299
Other		**564**		537
Less: Accumulated depreciation, depletion and amortization		**(19,997)**		(19,534)
Total property and equipment, net		**5,772**		4,955
Other long-term assets		**240**		249
TOTAL ASSETS	**$**	**7,521**	$	7,076
LIABILITIES AND EQUITY				
Current liabilities:				
Short-term debt	**$**	**–**	$	41
Accounts payable		**533**		473
Taxes payable		**62**		59
Interest payable		**70**		74
Dividends payable		**27**		27
Derivative liabilities		**64**		355
Other current liabilities		**24**		35
Total current liabilities		**780**		1,064
Long-term debt		**4,391**		4,612
Pension and other postretirement liabilities		**58**		49
Other long-term liabilities		**313**		434
Total long-term liabilities		**4,762**		5,095
Commitments and contingencies (see Note 8)				
Equity:				
Common stock, $0.01 par value; 1,250,000,000 shares authorized; issued 512,134,311 shares as of December 31, 2017 and 495,248,369 as of December 31, 2016		**5**		5
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 6.25% Series B Mandatory Convertible, $1,000 per share liquidation preference, 1,725,000 shares issued and outstanding as of December 31, 2017 and 2016, converted to common stock in January 2018		**–**		–
Additional paid-in capital		**4,698**		4,677
Accumulated deficit		**(2,679)**		(3,725)
Accumulated other comprehensive loss		**(44)**		(39)
Common stock in treasury, 31,269 shares as of December 31, 2017 and 2016		**(1)**		(1)
Total equity		**1,979**		917
TOTAL LIABILITIES AND EQUITY	**$**	**7,521**	$	7,076

The accompanying notes are an integral part of these consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the twelve months ended December 31,		
	2017	2016	2015
		(in millions)	
Cash Flows From Operating Activities:			
Net income (loss)	$ **1,046**	$ (2,643)	$ (4,556)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**504**	436	1,092
Impairment of natural gas and oil properties	**–**	2,321	6,950
Amortization of debt issuance costs	**9**	14	53
Deferred income taxes	**(71)**	(22)	(2,003)
(Gain) loss on derivatives, unsettled	**(451)**	373	155
Stock-based compensation	**24**	29	26
Gain on sale of assets, net	**(6)**	–	(283)
Restructuring charges	**–**	30	–
Loss on early extinguishment of debt	**70**	51	–
Other	**13**	8	34
Change in assets and liabilities:			
Accounts receivable	**(65)**	(30)	203
Accounts payable	**48**	(69)	(78)
Taxes payable	**4**	(5)	(28)
Interest payable	**(2)**	–	9
Other assets and liabilities	**(26)**	5	6
Net cash provided by operating activities	**1,097**	498	1,580
Cash Flows From Investing Activities:			
Capital investments	**(1,268)**	(593)	(1,798)
Acquisitions	**–**	–	(579)
Proceeds from sale of property and equipment	**10**	430	729
Other	**6**	1	10
Net cash used in investing activities	**(1,252)**	(162)	(1,638)
Cash Flows From Financing Activities:			
Payments on current portion of long-term debt	**(328)**	(1)	(1)
Payments on long-term debt	**(1,139)**	(1,175)	(500)
Payments on short-term debt	**–**	–	(4,500)
Payments on revolving credit facility	**–**	(3,268)	(3,024)
Borrowings under revolving credit facility	**–**	3,152	2,840
Payments on commercial paper	**–**	(242)	(7,988)
Borrowings under commercial paper	**–**	242	7,988
Change in bank drafts outstanding	**9**	(20)	12
Proceeds from issuance of long-term debt	**1,150**	1,191	2,950
Payment of debt issuance costs	**(24)**	(17)	(20)
Proceeds from issuance of common stock	**–**	1,247	669
Proceeds from issuance of mandatory convertible preferred stock	**–**	–	1,673
Preferred stock dividend	**(16)**	(27)	(79)
Cash paid for tax withholding	**(2)**	(9)	–
Other	**(2)**	(1)	–
Net cash provided by (used in) financing activities	**(352)**	1,072	20
Increase (decrease) in cash and cash equivalents	**(507)**	1,408	(38)
Cash and cash equivalents at beginning of year	**1,423**	15	53
Cash and cash equivalents at end of year	$ **916**	$ 1,423	$ 15

The accompanying notes are an integral part of these consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Common Stock		Preferred Stock					
	Shares Issued	Amount	Shares Issued	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)(1)	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total
	(in millions, except share amounts)							
Balance at December 31, 2014	354,488,992	$ 4	–	$ 1,019	$ 3,577	$ 62	$ –	$ **4,662**
Comprehensive loss:								
Net loss	–	–	–	–	(4,556)	–	–	**(4,556)**
Other comprehensive loss	–	–	–	–	–	(110)	–	**(110)**
Total comprehensive loss	–	–	–	–	–	–	–	**(4,666)**
Stock-based compensation	–	–	–	48	–	–	–	**48**
Preferred stock dividend	–	–	–	–	(106)	–	–	**(106)**
Issuance of common stock	30,000,000	–	–	669	–	–	–	**669**
Issuance of preferred stock	–	–	1,725,000	1,673	–	–	–	**1,673**
Issuance of restricted stock	5,821,125	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(103,162)	–	–	–	–	–	–	**–**
Treasury stock – non-qualified plan	–	–	–	–	–	–	(1)	**(1)**
Tax withholding – stock compensation	(73,869)	–	–	–	–	–	–	**–**
Issuance of stock awards	5,463	–	–	–	–	–	–	**–**
Non-controlling interest	–	–	–	–	3	–	–	**3**
Balance at December 31, 2015	390,138,549	$ 4	1,725,000	$ 3,409	$ (1,082)	$ (48)	$ (1)	$ **2,282**
Comprehensive loss:								
Net loss	–	–	–	–	(2,643)	–	–	**(2,643)**
Other comprehensive loss	–	–	–	–	–	9	–	**9**
Total comprehensive loss	–	–	–	–	–	–	–	**(2,634)**
Stock-based compensation	–	–	–	58	–	–	–	**58**
Preferred stock dividend	7,166,389	–	–	(27)	–	–	–	**(27)**
Exercise of stock options	44,880	–	–	–	–	–	–	**–**
Issuance of common stock	98,900,000	1	–	1,246	–	–	–	**1,247**
Issuance of restricted stock	87,472	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(165,483)	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(929,252)	–	–	(9)	–	–	–	**(9)**
Issuance of stock awards	5,814	–	–	–	–	–	–	**–**
Balance at December 31, 2016	495,248,369	$ 5	1,725,000	$ 4,677	$ (3,725)	$ (39)	$ (1)	$ **917**
Comprehensive income:								
Net income	–	–	–	–	1,046	–	–	**1,046**
Other comprehensive income	–	–	–	–	–	(5)	–	**(5)**
Total comprehensive income	–	–	–	–	–	–	–	**1,041**
Stock-based compensation	–	–	–	38	–	–	–	**38**
Preferred stock dividend	12,791,716			(16)				**(16)**
Issuance of restricted stock	5,055,208	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(742,028)	–	–	–	–	–	–	**–**
Performance units vested	121,208	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(340,234)	–	–	(1)	–	–	–	**(1)**
Issuance of stock awards	72	–	–	–	–	–	–	**–**
Balance at December 31, 2017	512,134,311	$ 5	1,725,000	$ 4,698	$ (2,679)	$ (44)	$ (1)	$ **1,979**

(1) Includes a net cumulative-effect adjustment of $59 million related to the recognition of previously unrecognized windfall tax benefits resulting from the adoption of ASU 2016-09 as of the beginning of 2017. This adjustment increased net deferred tax assets and the related income tax valuation allowance by the same amount.

The accompanying notes are an integral part of these consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Southwestern Energy Company (including its subsidiaries, collectively "Southwestern" or the "Company") is an independent energy company engaged in natural gas, oil and NGL exploration, development and production ("E&P"). The Company is also focused on creating and capturing additional value through its natural gas gathering and marketing businesses ("Midstream"). Southwestern conducts most of its businesses through subsidiaries and operates principally in two segments: E&P and Midstream.

Exploration and Production. Southwestern's primary business is the exploration for and production of natural gas, oil and NGLs, with current operations principally focused on the development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. The Company's operations in northeast Pennsylvania, herein referred to as "Northeast Appalachia," are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Operations in West Virginia and southwest Pennsylvania, herein referred to as "Southwest Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Collectively, Southwestern refers to its properties located in Pennsylvania and West Virginia as the "Appalachian Basin." The Company's operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. Southwestern has smaller holdings in Colorado and Louisiana, along with other areas in which the Company is testing potential new resources. The Company also has drilling rigs located in Pennsylvania, West Virginia and Arkansas and provides oilfield products and services, principally serving its E&P operations.

Midstream. Through the Company's midstream subsidiaries, Southwestern engages in natural gas gathering activities in Arkansas and Louisiana. These activities primarily support the Company's E&P operations and generate revenue from fees associated with the gathering of natural gas. Southwestern's marketing activities capture opportunities that arise through the marketing and transportation of the natural gas, oil and NGLs produced in its E&P operations.

In February 2018, the Company announced an initiative to actively pursue strategic alternatives for the Fayetteville Shale E&P and related Midstream gathering assets.

Basis of Presentation

The consolidated financial statements included in this Annual Report present the Company's financial position, results of operations and cash flows for the periods presented in accordance with accounting principles generally accepted in the United States ("GAAP"). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company evaluates subsequent events through the date the financial statements are issued. Certain reclassifications have been made to the prior year financial statements to conform to the 2017 presentation. The Company had $24 million in unamortized debt expense that was classified as a long-term asset at December 31, 2015, which is now presented as a contra-liability as a result of adoption of ASU 2015-03 in the first quarter of 2016. The effects of the reclassifications were not material to the Company's consolidated financial statements.

Principles of Consolidation

The consolidated financial statements include the accounts of Southwestern and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated.

In 2015, the Company purchased an 86% ownership in a limited partnership which owns and operates a gathering system in Northeast Appalachia as part of the WPX Property Acquisition (as defined and discussed in Note 3). Because the Company owns a controlling interest in the partnership, the operating and financial results are consolidated with the Company's E&P segment results. The investor's share of the partnership activity is reported in retained earnings in the consolidated financial statements. Net income attributable to noncontrolling interest for the years ended December 31, 2017 and 2016 was insignificant.

Revenue Recognition

Natural gas and liquids sales. Natural gas and liquids sales are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability of the revenue is reasonably assured. The Company uses the entitlement method that requires revenue recognition for the Company's net revenue interest of sales from its properties. Accordingly, natural gas and liquid sales are not recognized for deliveries in excess of the Company's net revenue interest, while natural gas and liquid sales are recognized for any under-delivered volumes. Production imbalances are generally recorded at estimated sales prices of the anticipated future settlements of the imbalances. The Company had no significant production imbalances at December 31, 2017 or 2016.

Marketing. The Company generally markets its natural gas and liquids, as well as some products produced by third parties, to marketers, local distribution companies and end-users, pursuant to a variety of contracts. Marketing revenues are recognized when delivery has occurred, title has transferred, the price is fixed or determinable and collectability of the revenue is reasonably assured.

Gas gathering. In certain areas, the Company gathers its natural gas as well as some natural gas produced by third parties pursuant to a variety of contracts. Gas gathering revenues are recognized when the service is performed, the price is fixed or determinable and collectability of the revenue is reasonably assured.

Major Customers

For the year ended December 31, 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.3% of total natural gas, oil and NGL sales. The Company believes that the loss of a major customer would not have a material adverse effect on its ability to sell its natural gas, oil and NGL production because alternative purchasers are available.

Cash and Cash Equivalents

Cash and cash equivalents are defined by the Company as short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash. Management considers cash and cash equivalents to have minimal credit and market risk as the Company monitors the credit status of the financial institutions holding its cash and marketable securities. The following table presents a summary of cash and cash equivalents as of December 31, 2017 and December 31, 2016:

	For the years ended December 31,	
(in millions)	**2017**	2016
Cash	$ 261	$ 254
Marketable securities [1]	605	1,169
Other cash equivalents	50	–
Total	$ 916	$ 1,423

(1) Consists of government stable value money market funds.

Certain of the Company's cash accounts are zero-balance controlled disbursement accounts. The Company presents the outstanding checks written against these zero-balance accounts as a component of accounts payable in the accompanying consolidated balance sheets. Outstanding checks included as a component of accounts payable totaled $17 million and $8 million as of December 31, 2017 and 2016, respectively.

Property, Depreciation, Depletion and Amortization

Natural Gas and Oil Properties. The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure). Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives designated for hedge accounting, to calculate the ceiling value of their reserves. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments.

Costs associated with unevaluated properties are excluded from the amortization base until the properties are evaluated or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and related capitalized interest are initially excluded from the amortization base. Leasehold costs are either transferred to the amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. The Company's decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on several factors, including drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2017, the Company had a total of $1,817 million of costs excluded from the amortization base, all of which related to its properties in the United States. Inclusion of some or all of these costs in the Company's United States properties in the future, without adding any associated reserves, could result in additional ceiling test impairments.

At December 31, 2017, the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.98 per MMBtu, West Texas Intermediate oil of $47.79 per barrel and NGLs of $14.41 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2017. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2017.

The Company's net book value of its United States and Canada natural gas and oil properties exceeded the ceiling by approximately $641 million (net of tax) at March 31, 2016, $297 million (net of tax) at June 30, 2016 and $506 million (net of tax) at September 30, 2016, resulting in non-cash ceiling test impairments in each of the quarters ending those dates. Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.48 per MMBtu, West Texas Intermediate oil of $39.25 per barrel and NGLs of $6.74 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2016. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2016.

The net book value of the Company's United States natural gas and oil properties exceeded the ceiling by $944 million (net of tax) at June 30, 2015 and $1,746 million (net of tax) at September 30, 2015 and resulted in non-cash ceiling test impairments for the quarters ended those dates. Cash flow hedges of natural gas production in place increased the ceiling amount by approximately $60 million and $40 million as of June 30, 2015 and September 30, 2015, respectively. Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.59 per MMBtu, West Texas Intermediate oil of $46.79 per barrel and NGLs of $6.82 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by $1,586 million (net of tax) at December 31, 2015 and resulted in a non-cash ceiling test impairment. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2015.

Gathering Systems. The Company's investment in gathering systems is primarily in a system serving its Fayetteville Shale operations in Arkansas. These assets are being depreciated on a straight-line basis over 25 years.

Capitalized Interest. Interest is capitalized on the cost of unevaluated natural gas and oil properties that are excluded from amortization.

Asset Retirement Obligations. The Company owns natural gas and oil properties, which require expenditures to plug and abandon the wells and reclaim the associated pads when the wells are no longer producing. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Impairment of long-lived assets. The carrying value of non-full cost pool long-lived assets is evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable.

Intangible assets. The carrying value of intangible assets are evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable. Intangible assets are amortized over their useful life.

Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate expected to be in effect for the year in which those temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. Deferred income taxes are provided to recognize the income tax effect of reporting certain transactions in different years for income tax and financial reporting purposes. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties. The Company recognizes penalties and interest related to uncertain tax positions within the provision (benefit) for income taxes line in the accompanying consolidated statements of operations. Additional information regarding uncertain tax positions along with the impact of recent tax reform legislation can be found in Note 9 – Income Taxes.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage defined commodity price risks and does not use them for speculative trading purposes. The Company uses fixed price swap agreements and options to financially protect sales of natural gas and certain NGLs. Gains and losses resulting from the settlement of derivative contracts have been recognized in gas sales if designated for hedge accounting treatment or gain (loss) on derivatives if not designated for hedge accounting treatment in the consolidated statements of operations when the contracts expire and the related physical transactions of the commodity hedged are recognized. Changes in the fair value of derivative instruments designated as cash flow hedges and not settled are included in other comprehensive income (loss) to the extent that they are effective in offsetting the changes in the cash flows of the hedged item. In contrast, gains and losses from the ineffective portion of derivative contracts designated for hedge accounting treatment are recognized currently and have an inconsequential impact in the consolidated statement of operations. Gains and losses from the unsettled portion of derivative contracts not designated for hedge accounting treatment are recognized in gain (loss) on derivatives in the consolidated statement of operations. See Note 4 – Derivatives and Risk Management and Note 6 – Fair Value Measurements for a discussion of the Company's hedging activities.

Earnings Per Share

Basic earnings per common share is computed by dividing net income (loss) attributable to common stock by the weighted average number of common shares outstanding during the reportable period. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding: the incremental shares that would have been outstanding assuming the exercise of dilutive stock options, the vesting of unvested restricted shares of common stock, performance units, the assumed conversion of mandatory convertible preferred stock and the shares of common stock declared as a preferred stock dividend. An antidilutive impact is an increase in earnings per share or a reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities.

In July 2016, the Company completed an underwritten public offering of 98,900,000 shares of its common stock, with an offering price to the public of $13.00 per share. Net proceeds from the common stock offering were approximately $1,247 million, after underwriting discount and offering expenses. The proceeds from the offering were used to repay $375 million of the $750 million term loan entered into in November 2015 and to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of the Company's outstanding senior notes due in the first quarter of 2018. The remaining proceeds of the offering were used for general corporate purposes.

In January 2015, the Company completed concurrent underwritten public offerings of 30,000,000 shares of its common stock and 34,500,000 depositary shares (both share counts include shares issued as a result of the underwriters exercising their options to purchase additional shares). The common stock offering was priced at $23.00 per share. Net proceeds from the common stock offering were approximately $669 million, after underwriting discount and offering expenses. Net proceeds from the depositary share offering were approximately $1.7 billion, after underwriting discount and offering expenses. Each depositary share represented a 1/20th interest in a share of the Company's mandatory convertible preferred stock, with a liquidation preference of $1,000 per share (equivalent to a $50 liquidation preference per depositary share).

The proceeds from the offerings were used to partially repay borrowings under the Company's $4.5 billion 364-day bridge facility with the remaining balance of the bridge facility fully repaid with proceeds from the Company's January 2015 public offering of $2.2 billion in long-term senior notes.

The mandatory convertible preferred stock entitled the holder to a proportional fractional interest in the rights and preferences of the convertible preferred stock, including conversion, dividend, liquidation and voting rights. The mandatory convertible preferred stock had the non-forfeitable right to participate on an as-converted basis at the conversion rate then in effect in any common stock dividends declared and as such, is considered a participating security. Accordingly, it has been included in the computation of basic and diluted earnings per share, pursuant to the two-class method. In the calculation of basic earnings per share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. The Company's participating securities do not participate in undistributed net losses because they are not contractually obligated to do so.

On January 12, 2018 the Company converted all outstanding shares of mandatory convertible preferred stock to 74,998,614 shares of the Company's common stock.

On December 18, 2017, the Company declared the quarterly dividend, payable to holders of the mandatory convertible preferred stock all in cash on January 16, 2018. Dividends declared in the first, second and third quarters of 2017 were settled partially in common stock for a total of 10,040,306 shares, as well as those in the first, second, third and fourth quarters of 2016 for a total of 9,917,799 shares. The dividends declared for all quarters in 2015 were paid in cash.

The following table presents the computation of earnings per share for the years ended December 31, 2017, 2016 and 2015:

	For the years ended December 31,		
(in millions, except share/per share amounts)	**2017**	2016	2015
Net income (loss)	**$ 1,046**	$ (2,643)	$ (4,556)
Mandatory convertible preferred stock dividend	**108**	108	106
Participating securities – mandatory convertible preferred stock	**123**	–	–
Net income (loss) attributable to common stock	**$ 815**	$ (2,751)	$ (4,662)
Number of common shares:			
Weighted average outstanding	**498,264,321**	435,337,402	380,521,039
Issued upon assumed exercise of outstanding stock options	**–**	–	–
Effect of issuance of non-vested restricted common stock	**1,061,056**	–	–
Effect of issuance of non-vested performance units	**1,478,920**	–	–
Effect of issuance of mandatory convertible preferred stock	**–**	–	–
Effect of declaration of preferred stock dividends	**–**	–	–
Weighted average and potential dilutive outstanding	**500,804,297**	435,337,402	380,521,039
Earnings (loss) per common share:			
Basic	**$ 1.64**	$ (6.32)	$ (12.25)
Diluted	**$ 1.63**	$ (6.32)	$ (12.25)

The following table presents the common stock shares equivalent excluded from the calculation of diluted earnings per share for the years ended December 31, 2017, 2016 and 2015, as they would have had an antidilutive effect:

	For the years ended December 31,		
	2017	2016	2015
Unvested stock options	**116,717**	3,692,697	3,835,234
Unvested share-based payment	**5,361,849**	959,233	1,990,383
Performance units	**765,689**	884,644	140,414
Mandatory convertible preferred stock	**74,999,895**	74,999,895	70,890,312
Total	**81,244,150**	80,536,469	76,856,343

Supplemental Disclosures of Cash Flow Information

The following table provides additional information concerning interest and income taxes paid as well as changes in noncash investing activities for the years ended December 31, 2017, 2016, and 2015:

	For the years ended December 31,		
(in millions)	**2017**	2016	2015
Cash paid during the year for interest, net of amounts capitalized	**$ 130**	$ 75	$ 6
Cash received during the year for income taxes	**(5)**	(15)	(6)
Increase (decrease) in noncash property additions	**25**	55	(10)

Stock-Based Compensation

The Company accounts for stock-based compensation transactions using a fair value method and recognizes an amount equal to the fair value of the stock options and stock-based payment cost in either the consolidated statement of operations or capitalizes the cost into natural gas and oil properties or gathering systems included in property and equipment. Costs are capitalized when they are directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties or directly related to the construction of the Company's gathering systems.

Treasury Stock

The Company maintains a non-qualified deferred compensation supplemental retirement savings plan for certain key employees whereby participants may elect to defer and contribute a portion of their compensation to a Rabbi Trust, as permitted by the plan. The Company includes the assets and liabilities of its supplemental retirement savings plan in its consolidated balance sheet. Shares of the Company's common stock purchased under the non-qualified deferred compensation arrangement are held in the Rabbi Trust, are presented as treasury stock and are carried at cost. As of December 31, 2017 and 2016, 31,269 shares were accounted for as treasury stock.

Foreign Currency Translation

The Company has designated the Canadian dollar as the functional currency for our activities in Canada. The cumulative translation effects of translating the accounts from the functional currency into the U.S. dollar at current exchange rates are included as a separate component of other comprehensive income within stockholders' equity.

New Accounting Standards Implemented in this Report

In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2016-09, Compensation – Stock Compensation (Topic 718) ("Update 2016-09"), to simplify accounting for share-based payment transactions including income tax consequences, classification of awards as either equity or liabilities, and the classification on the statement of cash flows. For public entities, Update 2016-09 became effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, with early adoption permitted. The Company adopted Update 2016-09 during the first quarter with an effective date of January 1, 2017. The recognition of previously unrecognized windfall tax benefits resulted in a net cumulative-effect adjustment of $59 million, which increased net deferred tax assets and the related income tax valuation allowance by the same amount as of the beginning of 2017. The amendments within Update 2016-09 related to the recognition of excess tax benefits and tax shortfalls in the income statement and presentation within the operating section of the statement of cash flows were adopted prospectively, with no adjustments made to prior periods. The Company has elected to account for forfeitures as they occur. The remaining provisions of this amendment did not have a material effect on its consolidated results of operations, financial position or cash flows.

New Accounting Standards Not Yet Implemented in this Report

In March 2017, the FASB issued Accounting Standards Update No. 2017-07, Compensation - Retirement Benefits (Topic 715) ("Update 2017-07"), which provides additional guidance on the presentation of net benefit cost in the statement of operations and on the components eligible for capitalization in assets. The guidance requires employers to disaggregate the service cost component from the other components of net benefit cost. The service cost component of the net periodic benefit cost shall be reported in the same line item as other compensation costs arising from services rendered by the employees during the period, except for amounts capitalized. All other components of net benefit cost shall be presented outside of a subtotal for income from operations. The guidance is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. The amendments in this update should be applied retrospectively for the presentation of the service cost component and the other components of net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic benefit cost in assets. The Company does not expect the impact of adopting Update 2017-07 to have a material effect on its consolidated financial statements and related disclosures.

In August 2016, the FASB issued Accounting Standards Update No. 2016-15, Statement of Cash Flows (Topic 230) ("Update 2016-15"), which seeks to reduce the existing diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. For public entities, Update 2016-15 becomes effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. The Company does not expect the impact of adopting Update 2016-15 to have a material effect on its consolidated financial statements and related disclosures.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases (Topic 842) ("Update 2016-02"), which seeks to increase transparency and comparability among organizations by, among other things, recognizing lease assets and lease liabilities on the balance sheet for leases classified as operating leases under previous GAAP and disclosing key information about leasing arrangements. The codification was amended through additional ASUs. Through December 2017, the Company made progress on contract reviews, drafting its accounting policies and evaluating the new disclosure requirements. The Company will continue assessing the effect that Update 2016-02 and related ASUs may have on its consolidated financial statements and related disclosures, and anticipates that its assessment will be complete in 2018. For public entities, Update 2016-02 becomes effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("Update 2014-09"), which seeks to provide clarity for recognizing revenue. The new standard removes inconsistencies in existing standards, changes the way companies recognize revenue from contracts with customers and increases disclosure requirements. The codification was amended through additional ASUs and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company performed an analysis, across all revenue streams, of the impact of Update 2014-09 and the related ASUs and did not identify any changes to its revenue recognition policies that would result in a material adjustment to its consolidated financial statements. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers, including disaggregation of revenue and any remaining performance obligations. The Company will adopt the new standard in January 2018 using the modified retrospective approach, under which the cumulative effect of initially applying the new guidance will be recognized as an adjustment to the opening balance of retained earnings in the first quarter of 2018. For public entities, the new standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period.

(2) REDUCTION IN WORKFORCE

In January 2016, the Company announced a 40% workforce reduction as a result of lower anticipated drilling activity. This reduction was substantially completed in the first quarter of 2016. In April 2016, the Company also partially restructured executive management, which was substantially completed in the second quarter of 2016.

The following table presents a summary of the restructuring charges for the year ended December 31, 2016:

		(in millions)
Severance (including payroll taxes)	**$**	**44**
Stock-based compensation		**24**
Pension and other post retirement benefits (1)		**5**
Other benefits		**3**
Outplacement services, other		**2**
Total restructuring charges (2)	**$**	**78**

(1) Includes non-cash charges related to the curtailment and settlement of the pension and other postretirement benefit plans. See Note 11 for additional details regarding the Company's retirement and employee benefit plans.

(2) Total restructuring charges were $75 million and $3 million for the Company's E&P and Midstream segments, respectively.

Severance payments and other separation costs related to restructuring were substantially completed by the end of 2016.

(3) ACQUISITIONS AND DIVESTITURES

In September 2016, the Company sold approximately 55,000 net acres in West Virginia for an adjusted sales price of approximately $401 million. The Company accounted for the sale of these natural gas and oil properties as adjustments to capitalized costs, with no recognition of gain or loss as the sale did not involve a significant change in proved reserves or significantly alter the relationship between costs and proved reserves. In September 2016, $48 million of the net proceeds was used to repay borrowings under the Company's term loan entered into in November 2015. The Company used the remaining net proceeds from the sale for general corporate purposes, including to fund capital projects.

In May 2015, the Company sold conventional oil and gas assets located in East Texas and the Arkoma Basin for approximately $211 million. The Company accounted for a portion of the sale of these natural gas and oil properties as adjustments to capitalized costs, with no recognition of gain or loss as the sale did not involve a significant change in proved reserves or significantly alter the relationship between costs and proved reserves. Approximately $205 million of the proceeds received were recorded as a reduction of the capitalized costs of the Company's natural gas and oil properties in the United States pursuant to the full cost method of accounting. The proceeds from the transaction were used to reduce the Company's debt.

In April 2015, the Company sold its gathering assets located in Bradford and Lycoming counties in northeast Pennsylvania for an adjusted sales price of approximately $489 million. The net book value of these assets was $206 million and was held in the Midstream segment as of the closing date. A gain on sale of $283 million was recognized and was included in gain on sale of assets, net on the consolidated statement of operations. The assets included approximately 100 miles of natural gas gathering pipelines, with nearly 600 million cubic feet per day of capacity. The proceeds from the transaction were used to repay a portion of the borrowings under the Company's $500 million term loan facility entered into in November 2015, which subsequently has been repaid in full.

In January 2015, the Company completed an acquisition of certain natural gas and oil assets including approximately 46,700 net acres in northeast Pennsylvania from WPX Energy, Inc. for an adjusted purchase price of $270 million (the "WPX Property Acquisition"). This acreage was producing approximately 50 million net cubic feet of gas per day from 63 operated horizontal wells as of December 2014. As part of this transaction, the Company assumed firm transportation capacity of 260 million cubic feet of gas per day predominantly on the Millennium pipeline. The firm transport is being amortized over 19 years. As of December 31, 2017 and 2016 the Company has amortized $26 million and $17 million, respectively. This transaction was funded with the revolving credit facility and was accounted for as a business combination. The following table summarizes the consideration paid for the WPX Property Acquisition and the fair value of the assets acquired and liabilities assumed as of the acquisition date:

Consideration:		*(in millions)*
Cash	$	270
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Assets acquired:		
Proved natural gas and oil properties		31
Unproved natural gas and oil properties		114
Intangible asset		109
Gathering system		22
Other		1
Total assets acquired		277
Liabilities assumed:		
Asset retirement obligations		(7)
Total liabilities assumed		(7)
	$	270

In January 2015, the Company completed an acquisition of certain natural gas and oil assets from Statoil ASA including approximately 30,000 net acres in West Virginia and southwest Pennsylvania for $357 million, which was comprised of approximately 20% of Statoil's interests in the properties, (the "Statoil Property Acquisition"). This transaction was accounted for as a business combination. The Company allocated the purchase price to natural gas and oil properties, based on the respective fair values of the assets acquired.

The above acquisitions qualified as business combinations, and as a result, the Company estimated the fair values of the assets acquired and liabilities assumed as of the acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. The Company used discounted cash flow models and made market assumptions as to future commodity prices, projections of estimated quantities of natural gas, oil and NGL reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as defined in Note 6 – Fair Value Measurements.

(4) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas, oil and NGLs which impacts the predictability of its cash flows related to the sale of those commodities. These risks are managed by the Company's use of certain derivative financial instruments. As of December 31, 2017, the Company's derivative financial instruments consisted of fixed price swaps, two-way costless collars, three-way costless collars, basis swaps, sold call options and interest rate swaps. During 2016, the Company settled all of its purchased put options. The Company had basis swaps, sold call options and interest rate swaps as of December 31, 2015. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps	The Company receives a fixed price for the contract and pays a floating market price to the counterparty.
Purchased put options	The Company purchases put options based on an index price from the counterparty by payment of a cash premium. If the index price is lower than the put's strike price at the time of settlement, the Company receives from the counterparty such difference between the index price and the purchased put strike price. If the market price settles above the put's strike price, no payment is due from either party.
Two-way costless collars	Arrangements that contain a fixed floor price (purchased put option) and a fixed ceiling price (sold call option) based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the ceiling price, the Company pays the counterparty the difference between the index price and ceiling price, (2) if the index price is between the floor and ceiling prices, no payments are due from either party, and (3) if the index price is below the floor price, the Company will receive the difference between the floor price and the index price.
Three-way costless collars	Arrangements that contain a purchased put option, a sold call option and a sold put option based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the sold call strike price, the Company pays the counterparty the difference between the index price and sold call strike price, (2) if the index price is between the purchased put strike price and the sold call strike price, no payments are due from either party, (3) if the index price is between the sold put strike price and the purchased put strike price, the Company will receive the difference between the purchased put strike price and the index price, and (4) if the index price is below the sold put strike price, the Company will receive the difference between the purchased put strike price and the sold put strike price.
Basis swaps	Arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.
Purchased call options	The Company purchases call options in exchange for a premium. If the market price exceeds the strike price of the call option at the time of settlement, the Company receives from the counterparty such difference between the index price and the purchased call strike price. If the market price settles below the call's strike price, no payment is due from either party.
Sold call options	The Company sells call options in exchange for a premium. If the market price exceeds the strike price of the call option at the time of settlement, the Company pays the counterparty such excess on sold call options. If the market price settles below the call's strike price, no payment is due from either party.
Interest rate swaps	Interest rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest rate changes.

The Company utilizes counterparties for its derivative instruments that it believes are creditworthy at the time the transactions are entered into, and the Company closely monitors the credit ratings of these counterparties. Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, the events in the financial markets in recent years demonstrate there can be no assurance that a counterparty will be able to meet its obligations to the Company.

The following table provides information about the Company's financial instruments that are sensitive to changes in commodity prices and that are used to protect the Company's exposure. None of the financial instruments below are designated for hedge accounting treatment. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates as of December 31, 2017:

		Weighted Average Price per MMBtu					
Financial protection on production	Volume *(Bcf)*	Swaps	Sold Puts	Purchased Puts	Sold Calls	Basis Differential	Fair value at December 31, 2017 *($ in millions)*
2018							
Fixed price swaps	194	$ 3.02	$ –	$ –	$ –	$ –	$ 38
Two-way costless collars	23	–	–	2.97	3.56	–	4
Three-way costless collars	272	–	2.40	2.97	3.37	–	46
Total	489						$ 88
2019							
Fixed price swaps	93	$ 3.00	$ –	$ –	$ –	$ –	$ 17
Three-way costless collars	108	–	2.50	2.95	3.32	–	9
Total	201						$ 26
Basis swaps							
2018	44	$ –	$ –	$ –	$ –	$ (0.48)	$ (21)
2019	–	–	–	–	–	(0.59)	–
Total	44						$ (21)

Purchased call options	Volume *(Bcf)*	Weighted Average Strike Price per MMBtu	Fair value at December 31, 2017 *($ in millions)*
2018	13	$ 3.23	$ 2 (1)
	13		$ 2
Sold call options			
2018	63	$ 3.50	$ (3)
2019	52	3.50	(5)
2020	68	3.63	(4)
2021	57	3.52	(6)
Total	240		$ (18)

(1) Excludes $1 million in premiums paid related to certain call options recognized as a component of derivative assets within current assets on the consolidated balance sheet. As certain call options settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the consolidated statements of operations.

The balance sheet classification of the assets and liabilities related to derivative financial instruments (none of which are designated for hedge accounting treatment) are summarized below as of December 31, 2017 and 2016:

	Derivative Assets		
	Balance Sheet Classification	Fair Value at December 31,	
		2017	2016
Derivatives not designated as hedging instruments:		*(in millions)*	
Fixed price swaps	Derivative assets	$ **38**	$ –
Two-way costless collars	Derivative assets	**5**	8
Three-way costless collars	Derivative assets	**82**	11
Basis swaps	Derivative assets	**2**	32
Purchased call options	Derivative assets	**2**	–
Fixed price swaps	Other long-term assets	**18**	1
Two-way costless collars	Other long-term assets	**–**	2
Three-way costless collars	Other long-term assets	**39**	100
Basis swaps	Other long-term assets	**–**	1
Total derivative assets		$ **186** (1)	$ 155

	Derivative Liabilities		
	Balance Sheet Classification	Fair Value at December 31,	
		2017	2016
Derivatives not designated as hedging instruments:		*(in millions)*	
Fixed price swaps	Derivative liabilities	$ **–**	175
Two-way costless collars	Derivative liabilities	**1**	49
Three-way costless collars	Derivative liabilities	**36**	70
Basis swaps	Derivative liabilities	**23**	13
Sold call options	Derivative liabilities	**3**	46
Interest rate swaps	Derivative liabilities	**1**	2
Fixed price swaps	Other long-term liabilities	**1**	3
Two-way costless collars	Other long-term liabilities	**–**	9
Three-way costless collars	Other long-term liabilities	**30**	122
Basis swaps	Other long-term liabilities	**–**	5
Sold call options	Other long-term liabilities	**15**	35
Interest rate swaps	Other long-term liabilities	**–**	1
Total derivative liabilities		$ **110**	$ 530

(1) Excludes $1 million in premiums paid related to certain call options currently recognized as a component of derivative assets within current assets on the consolidated balance sheet. As certain call options settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the consolidated statements of operations.

At December 31, 2017, the net fair value of the Company's financial instruments related to commodities was a $77 million asset. The net fair value of the Company's interest rate swaps was a $1 million liability as of December 31, 2017.

Derivative Contracts Designated for Hedge Accounting

All derivatives are recognized in the balance sheet as either an asset or liability and are measured at fair value, other than transactions for which normal purchase/normal sale is applied. Certain criteria must be satisfied in order for derivative financial instruments to be designated for hedge accounting. Unrealized gains and losses related to unsettled derivatives that have been designated for hedge accounting are recorded in either earnings or as a component of other comprehensive income until settled. In the period of settlement, the Company recognizes the gains and losses from these qualifying hedges in gas sales revenues. As of December 31, 2017 and 2016, the Company had no positions designated for hedge accounting treatment. In 2015, the Company had certain fixed price swaps that were designated for hedge accounting. For the year ended December 31, 2015, the Company reported pre-tax gains in other comprehensive income of $45 million related to the effective portion of the unsettled fixed price swaps. The ineffective portion of those fixed price swaps was recognized in earnings and had an inconsequential impact to the consolidated statement of operations for the year ended December 31, 2015. For the year ended December 31, 2015, pre-tax gains of $209 million on settled fixed price swaps were transferred from other comprehensive income into gas sales revenues in the consolidated statement of operations.

Derivative Contracts Not Designated for Hedge Accounting

As of December 31, 2017, the Company had no positions designated for hedge accounting treatment. Gains and losses on derivatives that are not designated for hedge accounting treatment, or that do not meet hedge accounting requirements, are recorded as a component of gain (loss) on derivatives on the consolidated statements of operations. Accordingly, the gain (loss) on derivatives component of the statement of operations reflects the gains and losses on both settled and unsettled derivatives. The Company calculates gains and losses on settled derivatives as the summation of gains and losses on positions which have settled within the reporting period. Only the settled gains and losses are included in the Company's realized commodity price calculations.

The Company is a party to interest rate swaps that were entered into to mitigate the Company's exposure to volatility in interest rates. The interest rate swaps have a notional amount of $170 million and expire in June 2020. The Company did not designate the interest rate swaps for hedge accounting treatment. Changes in the fair value of the interest rate swaps are included in gain (loss) on derivatives on the consolidated statements of operations.

The following tables summarize the before-tax effect of fixed price swaps, purchased put options, two-way costless collars, three-way costless collars, basis swaps, sold call options and interest rate swaps not designated for hedge accounting on the consolidated statements of operations for the years ended December 31, 2017 and 2016:

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Unsettled	Gain (Loss) on Derivatives, Unsettled Recognized in Earnings For the years ended December 31, 2017	2016
		(in millions)	
Fixed price swaps [1]	Gain (Loss) on Derivatives	**$ 232**	$ (177)
Two-way costless collars	Gain (Loss) on Derivatives	**52**	(48)
Three-way costless collars	Gain (Loss) on Derivatives	**136**	(81)
Basis swaps	Gain (Loss) on Derivatives	**(36)**	12
Purchased call options	Gain (Loss) on Derivatives	**2**	–
Sold call options	Gain (Loss) on Derivatives	**63**	(81)
Interest rate swaps	Gain (Loss) on Derivatives	**2**	2
Total gain (loss) on unsettled derivatives		**$ 451**	$ (373)

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled	Gain (Loss) on Derivatives, Settled [2] Recognized in Earnings For the years ended December 31, 2017	2016
		(in millions)	
Fixed price swaps [1]	Gain (Loss) on Derivatives	**$ (9)**	$ –
Purchased put options	Gain (Loss) on Derivatives	**–**	11
Two-way costless collars	Gain (Loss) on Derivatives	**–**	3
Three-way costless collars	Gain (Loss) on Derivatives	**(1)**	1
Basis swaps	Gain (Loss) on Derivatives	**(6)**	21
Sold call options	Gain (Loss) on Derivatives	**(11)** [3]	–
Interest rate swaps	Gain (Loss) on Derivatives	**(2)**	(2)
Total gain (loss) on settled derivatives [4]		**$ (29)**	$ 34
Total gain (loss) on derivatives		**$ 422**	$ (339)

(1) Includes the Company's fixed price swaps on natural gas, ethane and propane. As of December 31, 2017, the amount of unsettled and settled fixed price swaps related to ethane and propane was immaterial.

(2) The Company calculates gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period.

(3) Includes $5 million amortization of premiums paid related to certain call options for the year ended December 31, 2017.

(4) Excluding interest rate swaps and settled ethane fixed price swaps, these amounts are included, along with gas sales revenues, in the calculation of the Company's realized natural gas price. Settled ethane fixed price swaps are included, along with NGL sales revenues, in the calculation of the Company's realized NGL price.

(5) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following tables detail the components of accumulated other comprehensive income (loss), net of related tax effects, for the year ended December 31, 2017:

	For the year ended December 31, 2017		
(in millions)	Pension and Other Postretirement	Foreign Currency	Total
Beginning balance, December 31, 2016	$ (19)	$ (20)	$ (39)
Other comprehensive income (loss) before reclassifications [1]	(13)	6	(7)
Amounts reclassified from other comprehensive income (loss) [1] [2]	2	–	2
Net current-period other comprehensive income (loss)	(11)	6	(5)
Ending balance, December 31, 2017	**$ (30)**	**$ (14)**	**$ (44)**

(1) Deferred tax activity related to pension and other postretirement benefits was offset by a valuation allowance, resulting in no tax expense recorded for the period.

(2) See separate table below for details about these reclassifications.

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from Accumulated Other Comprehensive Income For the year ended December 31, 2017 (in millions)
Pension and other postretirement:		
Amortization of prior service cost and net loss [1]	General and administrative expenses	$ 2
	Provision (benefit) for income taxes [2]	–
	Net income	$ 2
Total reclassifications for the period	Net income	$ 2

(1) See Note 11 for additional details regarding the Company's retirement and employee benefit plans.

(2) Deferred tax activity related to pension and other postretirement benefits was offset by a valuation allowance, resulting in no tax expense recorded for the period.

(6) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2017 and 2016 were as follows:

	December 31, 2017		December 31, 2016	
(in millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Cash and cash equivalents	**$ 916**	**$ 916**	$ 1,423	$ 1,423
2015 term loan due December 2020	**–**	**–**	327	327
2016 term loan due December 2020 [1]	**1,191**	**1,191**	1,191	1,191
Senior notes	**3,242**	**3,358**	3,166	3,182
Derivative instruments, net [2]	**76**	**76**	(375)	(375)

(1) The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due in January 2020. As of December 31, 2017, the Company has redeemed and refinanced $758 million principal amount of the 2020 senior notes.

(2) Excludes $1 million in premiums paid related to certain purchased call options currently recognized as a component of derivative assets within current assets on the consolidated balance sheet.

The carrying values of cash and cash equivalents, accounts receivable, other current assets, accounts payable and other current liabilities on the consolidated balance sheets approximate fair value because of their short-term nature. For debt and derivative instruments, the following methods and assumptions were used to estimate fair value:

Debt: The fair values of the Company's senior notes were based on the market value of the Company's publicly traded debt as determined based on the yield of the Company's senior notes.

The carrying values of the borrowings under the Company's term loan facilities and unsecured revolving credit facility approximate fair value because the interest rate is variable and reflective of market rates. The Company considers the fair value of its debt to be a Level 2 measurement on the fair value hierarchy.

Derivative Instruments: The fair value of all derivative instruments is the amount at which the instrument could be exchanged currently between willing parties. The amounts are based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

The fair value hierarchy prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 valuations – Consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority.

Level 2 valuations – Consist of quoted market information for the calculation of fair market value.

Level 3 valuations – Consist of internal estimates and have the lowest priority.

The Company has classified its derivatives into these levels depending upon the data utilized to determine their fair values. The Company's fixed price swaps (Level 2) are estimated using third-party discounted cash flow calculations using the NYMEX futures index. The Company utilized discounted cash flow models for valuing its interest rate derivatives (Level 2). The net derivative values attributable to the Company's interest rate derivative contracts as of December 31, 2017 are based on (i) the contracted notional amounts, (ii) active market-quoted London Interbank Offered Rate ("LIBOR") yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's sold call options, purchased put options, two-way costless collars and three-way costless collars (Level 3) are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX futures index, interest rates, volatility and credit worthiness. The Company's basis swaps (Level 3) are estimated using third-party calculations based upon forward commodity price curves.

Inputs to the Black-Scholes model, including the volatility input, which is the significant unobservable input for Level 3 fair value measurements, are obtained from a third-party pricing source, with independent verification of the most significant inputs on a monthly basis.

Assets and liabilities measured at fair value on a recurring basis are summarized below:

	December 31, 2017			
	Fair Value Measurements Using:			
(in millions)	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Fixed price swap assets	$ –	$ 56	$ –	$ 56
Two-way costless collar assets	–	–	5	5
Three-way costless collar assets	–	–	121	121
Basis swap assets	–	–	2	2
Purchased call option assets	–	–	2	2
Fixed price swap liabilities	–	(1)	–	(1)
Two-way costless collar liabilities	–	–	(1)	(1)
Three-way costless collar liabilities	–	–	(66)	(66)
Basis swap liabilities	–	–	(23)	(23)
Sold call option liabilities	–	–	(18)	(18)
Interest rate swap liabilities	–	(1)	–	(1)
Total	$ –	$ 54	$ 22	$ 76

(in millions)	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
	December 31, 2016			
	Fair Value Measurements Using:			
Fixed price swap assets	$ –	$ 1	$ –	$ 1
Two-way costless collar assets	–	–	10	10
Three-way costless collar assets	–	–	111	111
Basis swap assets	–	–	33	33
Fixed price swap liabilities	–	(178)	–	(178)
Two-way costless collar liabilities	–	–	(58)	(58)
Three-way costless collar liabilities	–	–	(192)	(192)
Basis swap liabilities	–	–	(18)	(18)
Sold call option liabilities	–	–	(81)	(81)
Interest rate swap liabilities	–	(3)	–	(3)
Total	$ –	$ (180)	$ (195)	$ (375)

The table below presents reconciliations for the change in net fair value of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the years ended December 31, 2017 and 2016. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company's judgment, reflect reasonable assumptions a marketplace participant would have used as of December 31, 2017 and 2016.

(in millions)	For the years ended December 31, 2017	2016
Balance at beginning of period	**$ (195)**	$ 3
Total gains (losses):		
Included in earnings	**199**	(162)
Settlements [(1)]	**18**	(36)
Transfers into/out of Level 3	**–**	–
Balance at end of period	**$ 22**	$ (195)
Change in gains (losses) included in earnings relating to derivatives still held as of December 31,	**$ 217**	$ (198)

(1) Includes $5 million amortization of premiums paid related to certain call options for the year ended December 31, 2017.

See Note 11 – Retirement and Employee Benefit Plans for a discussion of the fair value measurement of the Company's pension plan assets.

(7) DEBT

The components of debt as of December 31, 2017 and 2016 consisted of the following:

(in millions)	**Debt Instrument**	**Unamortized Issuance Expense**	**Unamortized Debt Discount**	**Total**
	December 31, 2017			
Long-term debt:				
Variable rate (3.980% at December 31, 2017) 2016 term loan facility, due December 2020 [(1)]	**$ 1,191**	**$ (8)**	**$ –**	**$ 1,183**
4.05% Senior Notes due January 2020 [(2)(3)]	**92**	**–**	**–**	**92**
4.10% Senior Notes due March 2022	**1,000**	**(7)**	**–**	**993**
4.95% Senior Notes due January 2025 [(2)]	**1,000**	**(8)**	**(2)**	**990**
7.50 % Senior Notes due April 2026	**650**	**(10)**	**–**	**640**
7.75 % Senior Notes due October 2027	**500**	**(7)**	**–**	**493**
Total long-term debt	**$ 4,433**	**$ (40)**	**$ (2)**	**$ 4,391**

	December 31, 2016			
(in millions)	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	Total
Short-term debt:				
7.35% Senior Notes due October 2017	$ 15	$ –	$ –	$ 15
7.125% Senior Notes due October 2017	25	–	–	25
7.15% Senior Notes due June 2018 (3)	1	–	–	1
Total short-term debt	$ 41	$ –	$ –	$ 41
Long-term debt:				
Variable rate (3.220% at December 31, 2016) term loan facility, due December 2020 (3)	$ 327	$ (2)	$ –	$ 325
Variable rate (3.220% at December 31, 2016) term loan facility, due December 2020 (1)	1,191	(10)	–	1,181
3.30% Senior Notes due January 2018 (2) (3)	38	–	–	38
7.50% Senior Notes due February 2018 (3)	212	–	–	212
7.15% Senior Notes due June 2018 (3)	25	–	–	25
4.05% Senior Notes due January 2020 (2) (3)	850	(5)	–	845
4.10% Senior Notes due March 2022	1,000	(4)	(1)	995
4.95% Senior Notes due January 2025 (2)	1,000	(7)	(2)	991
Total long-term debt	$ 4,643	$ (28)	$ (3)	$ 4,612
Total debt	$ 4,684	$ (28)	$ (3)	$ 4,653

(1) The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due in January 2020. As of December 31, 2017, the Company has redeemed and refinanced $758 million principal amount of the 2020 senior notes.

(2) In February and June 2016, Moody's and S&P downgraded certain senior notes, increasing the interest rates by 175 basis points effective July 2016. As a result of the downgrades, interest rates increased to 5.05% for the 2018 Notes, 5.80% for the 2020 Notes and 6.70% for the 2025 Notes.

(3) In 2017, the Company repurchased $38 million principal amount of its outstanding 3.30% Senior Notes due January 2018, $212 million principal amount of its outstanding 7.50% Senior Notes due February 2018, $26 million principal amount of its outstanding 7.15% Senior Notes due June 2018 and $758 million principal amount of its outstanding 4.05% Senior Notes due January 2020. The Company also repaid the outstanding $25 million of its outstanding 7.125% Senior Notes and $15 million of its 7.35% Senior Notes due October 2017 and the remaining $327 million principal amount of its term loan entered into in November 2015. The Company recognized a $70 million loss on the extinguishment of debt.

The following is a summary of scheduled debt maturities by year as of December 31, 2017:

	(in millions)
2018	$ –
2019	–
2020	1,283
2021	–
2022	1,000
Thereafter	2,150
	$ 4,433

Senior Notes

In January 2015, the Company completed a public offering of $350 million aggregate principal amount of its 3.30% senior notes due 2018 (the "2018 Notes"), $850 million aggregate principal amount of its 4.05% senior notes due 2020 (the "2020 Notes") and $1.0 billion aggregate principal amount of its 4.95% senior notes due 2025 (the "2025 Notes" together with the 2018 and 2020 Notes, the "Notes"), with net proceeds from the offering totaling approximately $2.2 billion after underwriting discounts and offering expenses. The interest rates on the Notes are determined based upon the public bond ratings from Moody's and S&P. Downgrades on the Notes from either rating agency increase interest costs by 25 basis points per downgrade level and upgrades decrease interest costs by 25 basis points per upgrade level, up to the stated coupon rate, on the following semi-annual bond interest payment. In February and June 2016, Moody's and S&P downgraded the Notes, increasing the interest rates by 175 basis points effective July 2016. As a result of these downgrades, interest rates increased to 5.05% for the 2018 Notes, 5.80% for the 2020 Notes and 6.70% for the 2025 Notes. In the event of future downgrades, the coupons for this series of notes are capped at 5.30%, 6.05% and 6.95%, respectively. The first coupon payment to the bondholders at the higher interest rates was paid in January 2017.

During the first half of 2017, the Company redeemed or repurchased (i) $38 million principal amount of its outstanding 2018 Notes, (ii) $212 million principal amount of its outstanding 7.50% Senior Notes due February 2018 and (iii) $26 million principal amount of its outstanding 7.15% Senior Notes due June 2018, and recognized an $11 million loss on the extinguishment of debt.

In September 2017, the Company completed a public offering of $650 million aggregate principal amount of its 7.50% senior notes due 2026 (the "2026 Notes") and $500 million aggregate principal amount of its 7.75% senior notes due 2027 (the "2027 Notes"), with net proceeds from the offering totaling approximately $1.1 billion after underwriting discounts and offering expenses. Both series of senior notes were sold to the public at face value. The proceeds from this offering were used to purchase $758 million of the Company's 2020 Notes in a tender offer and to repay the outstanding balance of $327 million on the Company's 2015 Term Loan. The Company recognized a loss on extinguishment of debt of $59 million, which included $53 million of premiums paid.

In October 2017, the Company retired $40 million principal amount outstanding on its 2017 Senior Notes.

In November 2017, the Company solicited and received consent to amend certain restrictive covenants contained in the indentures governing the Company's 2022 Notes and the 2025 Notes. These amendments conform certain covenants of the 2022 Notes and 2025 Notes to all other series of senior notes.

2016 Credit Facility

In June 2016, the Company reduced its existing $2.0 billion unsecured revolving credit facility, entered into in December 2013, to $66 million and entered into a new credit agreement for $1,934 million, consisting of a $1,191 million secured term loan and a new $743 million unsecured revolving credit facility, which matures in December 2020. The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due January 2020. In September 2017, the Company used a portion of the proceeds from the September 2017 debt offering to settle a tender offer by purchasing an aggregate principal amount of approximately $758 million of its outstanding senior notes due in January 2020. The $1,191 million secured term loan is fully drawn, with approximately $285 million of this balance used to pay down the previous revolving credit facility balance in its entirety. As of December 31, 2017, there were no borrowings under either revolving credit facility; however, $323 million in letters of credit was outstanding under the 2016 revolving credit facility.

Loans under the 2016 credit agreement are subject to varying rates of interest based on whether the loan is a Eurodollar loan or an alternate base rate loan. Eurodollar loans bear interest at the Eurodollar rate, which is adjusted LIBOR plus applicable margins ranging from 1.750% to 2.500%. Alternate base rate loans bear interest at the alternate base rate plus the applicable margin ranging from 0.750% to 1.500%. The interest rate on the term loan facility is determined based upon the Company's public debt ratings and was 250 basis points over LIBOR as of December 31, 2017.

The 2016 term loan and revolving credit facility contain financial covenants that impose certain restrictions on the Company. In September 2017, the Company amended its 2016 credit agreement to reflect the following:

- Increase the minimum interest coverage ratio to 2.00x commencing with the fiscal quarter ended June 30, 2017 and continued over the life of the 2016 credit agreement;

- Modify the minimum liquidity covenant such that either (1) if leverage is less than 4.00x or if the 2016 revolving credit facility has been terminated, there is no minimum liquidity covenant, or (2) the Company can elect to replace the minimum liquidity covenant with a maximum leverage ratio of no more than 5.50x for the fiscal quarter ending December 31, 2017, 5.00x for the fiscal quarters ending March 31, 2018 and June 30, 2018 and 4.50x thereafter; and

- Modify the mandatory prepayment and commitment reduction provisions to permit the Company to retain the first $500.0 million of net cash proceeds from asset sales that would have otherwise been required to prepay amounts outstanding under the 2016 revolving credit facility and/or reduce commitments under the 2016 revolving credit facility.

As of December 31, 2017, the Company has not elected to replace the minimum liquidity covenant with a maximum leverage covenant. Therefore, under the amended credit agreement, should the leverage ratio exceed 4.00x, the Company would be subject to a minimum liquidity requirement of $300 million. The financial covenant with respect to the maximum leverage ratio consists of total debt divided by EBITDAX. The financial covenant with respect to minimum interest coverage consists of EBITDAX divided by consolidated interest expense. EBITDAX, as defined in the Company's 2016 credit agreement, excludes the effects of interest expense, income taxes, depreciation, depletion and amortization, any non-cash impacts from impairments, certain non-cash hedging activities, stock-based compensation expense, non-cash gains or losses on asset sales, unamortized issuance cost, unamortized debt discount and certain restructuring costs. Collateral for the secured term loan is principally the Company's E&P properties in the Fayetteville Shale area, the equity of its subsidiaries and cash and marketable securities on hand, and the credit agreement requires a minimum collateral coverage ratio of 1.50x for the 2016 secured term loan. This collateral also may support all or a part of revolving credit extensions depending on restrictions in the Company's senior notes indentures.

As of December 31, 2017, the Company was in compliance with all of the covenants of this credit agreement. Although the Company does not anticipate any violations of the financial covenants, its ability to comply with these covenants is dependent upon the success of its exploration and development program and upon factors beyond the Company's control, such as the market prices for natural gas, oil and NGLs.

2013 Credit Facility

In December 2013, the Company entered into a credit agreement that exchanged its previous revolving credit facility. Under the revolving credit facility, the Company had a borrowing capacity of $2.0 billion. The revolving credit facility was unsecured and was not guaranteed by any subsidiaries. In June 2016, this credit facility was substantially exchanged for a new credit facility comprised of a $1,191 million secured term loan and a new $743 million revolving credit facility. The borrowing capacity of the original 2013 credit agreement was reduced from $2.0 billion to $66 million, remains unsecured and the maturity remains December 2018. As of December 31, 2017, there were no borrowings under this facility.

The existing unsecured 2013 revolving credit facility includes a financial covenant under which the Company may not have total debt in excess of 60% of its total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any full cost ceiling impairments, certain hedging activities and the Company's pension and other postretirement liabilities. At December 31, 2017, debt constituted 31% of the Company's adjusted book capital.

2015 Term Facility

In November 2015, the Company entered into a $750 million unsecured three-year term loan credit agreement with various lenders that was utilized to repay borrowings under the revolving credit facility. In 2016, the Company repaid $423 million of the $750 million unsecured term loan from a portion of the net proceeds of the July 2016 equity offering along with proceeds received from a non-core asset sale. In September 2017, the remaining outstanding balance of $327 million was repaid, and this term loan was terminated.

(8) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of December 31, 2017, the Company's contractual obligations for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems totaled approximately $9.2 billion, $3.0 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. The Company also had guarantee obligations of up to $832 million of that amount. As of December 31, 2017, future payments under non-cancelable firm transportation and gathering agreements are as follows:

	Payments Due by Period					
(in millions)	**Total**	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 years	More than 8 Years
Infrastructure Currently in Service	**$ 6,235**	$ 671	$ 1,240	$ 884	$ 1,155	$ 2,285
Pending Regulatory Approval and/or Construction [(1)]	**2,936**	31	325	369	587	1,624
Total Transportation Charges	**$ 9,171**	$ 702	$ 1,565	$ 1,253	$ 1,742	$ 3,909

(1) Based on the estimated in-service dates as of December 31, 2017.

The Company leases pressure pumping equipment for its E&P operations under a single lease that expires in 2021. The current aggregate annual payment under this lease in approximately $7 million. The Company has 7 leases for drilling rigs for its E&P operations that expire through 2021 with a current aggregate annual payment of approximately $13 million. The lease payments for the pressure pumping equipment, as well as other operating expenses for the Company's drilling operations, are capitalized to natural gas and oil properties and are partially offset by billings to third-party working interest owners.

The Company leases compressors, aircraft, vehicles, office space and equipment under non-cancelable operating leases expiring through 2027. As of December 31, 2017, future minimum payments under these non-cancelable leases accounted for as operating leases are approximately $65 million in 2018, $58 million in 2019, $47 million in 2020, $28 million in 2021, $4 million in 2022 and $11 million thereafter.

The Company also has commitments for compression services and rentals related to its Midstream and E&P segments. As of December 31, 2017, future minimum payments under these non-cancelable agreements are approximately $12 million in 2018 and $3 million in 2019.

Environmental Risk

The Company is subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or results of operations of the Company.

Litigation

The Company is subject to various litigation, claims and proceedings that have arisen in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties, employment matters, traffic accidents and pollution, contamination or nuisance. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. Management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on the Company's financial position, results of operations or cash flows for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future.

Arkansas Royalty Litigation

In June 2017, the jury returned a verdict in favor of the Company on all counts in *Smith v. SEECO, Inc. et al.*, a class action in the United States District Court for the Eastern District of Arkansas. The plaintiff had alleged that the Company had underpaid lessors of lands in Arkansas by deducting from royalty payments costs for gathering, transportation and compression of natural gas in excess of what is permitted by the relevant leases and asserted claims for, among other things, breach of contract, fraud, civil conspiracy, unjust enrichment and violation of certain Arkansas statutes. Following the verdict, the court entered judgment in favor of the Company on all claims. The trial court denied the plaintiff's motion for a new trial, and the plaintiff has filed a notice of appeal with the United States Court of Appeals for the Eighth Circuit. Briefing is not complete, and the Court of Appeals has not yet determined whether to hear oral argument. Independent of the plaintiff's appeal, several different parties sought to intervene in the *Smith* case prior to or shortly after trial, and have appealed the trial court's order denying their request to intervene. Briefing is complete in the intervenors' appeal, and oral argument is expected to occur sometime in the second quarter.

The plaintiff class in *Smith* comprises the vast majority of lessors of lands in Arkansas for which leases permit deductions for these types of costs. Most of the remaining lessors are named plaintiffs or members of classes in other pending lawsuits. In particular, two actions on behalf of certified classes of only Arkansas residents pending in state courts in Arkansas (one is set for trial during the third quarter of 2018; the other does not have a trial date) and three cases (all currently stayed) that were filed in Arkansas state court on behalf of a total of 248 individually named plaintiffs, two of which have been removed to federal court, have been assigned to the same court that held the *Smith* trial. Management believes that, as the *Smith* jury concluded, the deductions from royalty payments were calculated in accordance with the leases. The Company currently does not anticipate that these other cases are likely to have a material adverse effect on the results of operations, financial position or cash flows of the Company.

Indemnifications

The Company provides certain indemnifications in relation to dispositions of assets. These indemnifications typically relate to disputes, conditions, litigation or tax matters existing at the date of disposition. No material liabilities have been recognized in connection with these indemnifications.

(9) INCOME TAXES

The provision (benefit) for income taxes included the following components:

(in millions)	**2017**	2016	2015
Current:			
Federal	**$ (22)**	$ (6)	$ 1
State	**–**	(1)	(3)
	(22)	(7)	(2)
Deferred:			
Federal	**(71)**	(22)	(1,697)
State	**–**	–	(304)
Foreign	**–**	–	(2)
	(71)	(22)	(2,003)
Benefit for income taxes	**$ (93)**	$ (29)	$ (2,005)

The provision for income taxes was an effective rate of (10%) in 2017, 1% in 2016 and 31% in 2015. The following reconciles the provision for income taxes included in the consolidated statements of operations with the provision which would result from application of the statutory federal tax rate to pre-tax financial income:

(in millions)	**2017**	2016	2015
Expected provision (benefit) at federal statutory rate	**$ 333**	$ (935)	$ (2,296)
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	**16**	(79)	(194)
Nondeductible expenses	**–**	–	–
Rate impacts due to tax reform	**370**	–	–
Changes to valuation allowance due to tax reform	**(370)**	–	–
AMT tax reform impact – valuation allowance release	**(68)**	–	–
Change in uncertain tax positions	**(5)**	(19)	(7)
Change in valuation allowance	**(364)**	1,002	495
Other	**(5)**	2	(3)
Benefit for income taxes	**$ (93)**	$ (29)	$ (2,005)

Our effective tax rate decreased in 2017, as compared with 2016, primarily due to the Tax Reform impacts on rate, alternative minimum tax and the valuation allowance in place, as well as changes to the overall valuation allowance activity during 2017.

The components of the Company's deferred tax balances as of December 31, 2017 and 2016 were as follows:

(in millions)	**2017**	2016
Deferred tax liabilities:		
Differences between book and tax basis of property	**$ 395**	$ 81
Derivative activity	**19**	–
Other	**1**	1
	415	82
Deferred tax assets:		
Accrued compensation	**29**	38
Alternative minimum tax credit carryforward	**–**	100
Accrued pension costs	**14**	19
Asset retirement obligations	**41**	53
Net operating loss carryforward	**1,043**	1,177
Derivative activity	**–**	142
Other	**20**	29
	1,147	1,558
Valuation allowance	**(732)**	(1,476)
Net deferred tax liability	**$ –**	$ –

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (Tax Reform), which made significant changes to the U.S. federal income tax law affecting the Company. Major changes in this legislation applicable to the Company relate to the corporate rate change, repeal of the alternative minimum tax, interest deductibility limitations, net operating loss carryforward limitations, changes to certain executive compensation and full expensing provisions related to business assets. The Company continues to examine the impact of this legislation, and although certain aspects of it are uncertain and subject to future regulations, this legislation is expected to positively impact the Company due to the lower federal rate and the repeal of the alternative minimum tax, as outlined below:

- Beginning January 1, 2018, the U.S. corporate income tax rate will be 21%. The Company is required to recognize the impacts of this rate change on its deferred tax assets and liabilities in the period enacted. However, as the Company has a full valuation allowance on its net deferred tax asset, any deferred tax recognized due to the change in rate will be offset with a change in the valuation allowance. Therefore, there is no overall impact to the financial statements in 2017 due to this change in rate.

- The Tax Reform also repealed the corporate alternative minimum tax for tax years beginning on or after January 1, 2018 and provides for existing alternative minimum tax credit carryovers to be refunded beginning in 2018. The Company has approximately $68 million in refundable credits that are expected to be fully refunded between 2018 and 2021. As such, the valuation allowance in place at the end of 2017 related to these credits have been released and any credits remaining were reclassed to a receivable.

- Other provisions in the legislation, such as interest deductibility and changes to executive compensation plans are not expected to have material implications to the Company's financial condition due to the Company's current net operating loss carryforward position.

In 2017, the Company received state income tax refunds of less than $1 million and received $4.2 million in federal income tax refunds. In 2016, the Company paid less than $1 million in state income taxes and received $15 million in federal income tax refunds. The Company's net operating loss carryforward as of December 31, 2017 was $4.1 billion and $2.7 billion for federal and state reporting purposes, respectively, the majority of which will expire between 2029 and 2037. Additionally, the Company has an income tax net operating loss carryforward related to its Canadian operations of $29 million, with expiration dates of 2030 through 2037. The Company also had a statutory depletion carryforward of $13 million as of December 31, 2017.

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess the likelihood, the Company uses estimates and judgment regarding future taxable income, and considers the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include current financial position, results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as current and forecasted business economics of the oil and gas industry.

The Company maintained its net deferred tax asset position at December 31, 2017 primarily due to the prior write-downs of the carrying value of natural gas and oil properties. The Company believes it is more likely than not that these deferred tax assets will not be realized and accordingly maintained our full valuation allowance to adjust the remaining deferred tax asset to zero for the year ended December 31, 2017, reflected $807 million as a component of income tax expense and $63 million as a reduction of equity. Management assesses available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. In management's view, the cumulative loss incurred over the three-year period ending December 31, 2017, outweighs any positive factors, such as the possibility of future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as future expected growth.

A reconciliation of the changes to the valuation allowance is as follows:

	(in millions)
Valuation allowance as of December 31, 2016	$ 1,476
Changes based on 2017 activity	(364)
Tax reform – rate change	(370)
Tax reform – AMT repeal	(68)
Release of prior uncertain tax position	(5)
Equity – windfall tax benefit release	59
Equity – pension benefits in OCI	4
Valuation allowance as of December 31, 2017	**$ 732**

On March 30, 2016, the FASB modified its accounting policy on share-based payments (ASU 2016-09). Updates included tax impacts related to the treatment of excess tax benefits ("windfalls") and deficiencies ("shortfalls") were made and became effective on January 1, 2017. The Company had previously unrecognized tax "windfall" benefits of $149 million as of December 31, 2016, which were released in the first quarter of 2017. The recognition of previously unrecognized windfall tax benefits resulted in a net cumulative-effect adjustment of $59 million, which increased net deferred tax assets and the related income tax valuation allowance by the same amount as of the beginning of 2017. As of December 31, 2017, no unrecognized tax benefits exist related to share-based payments.

A tax position must meet certain thresholds for any of the benefit of the uncertain tax position to be recognized in the financial statements. As of December 31, 2017, the amount of unrecognized tax benefits related to alternative minimum tax was $12 million. The uncertain tax position identified would not have a material effect on the effective tax rate. No material changes to the current uncertain tax position are expected within the next 12 months. As of December 31, 2017, the Company had accrued a liability of less than $1 million of interest related to this uncertain tax position. The Company recognizes penalties and interest related to uncertain tax positions in income tax expense.

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

(in millions)		**2017**		2016
Unrecognized tax benefits at beginning of period	**$**	**17**	$	37
Additions based on tax positions related to the current year		**–**		–
Additions to tax positions of prior years		**–**		–
Reductions to tax positions of prior years		**(5)**		(20)
Unrecognized tax benefits at end of period	**$**	**12**	$	17

The Internal Revenue Service is currently auditing the Company's federal income tax return for 2014. The income tax years 2014 to 2017 remain open to examination by the major taxing jurisdictions to which the Company is subject.

(10) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the Company's 2017 and 2016 activity related to asset retirement obligations:

(in millions)		**2017**		2016
Asset retirement obligation at January 1	**$**	**141**	$	201
Accretion of discount		**8**		10
Obligations incurred		**3**		1
Obligations settled/removed (1)		**(10)**		(45)
Revisions of estimates		**23**		(26)
Asset retirement obligation at December 31	**$**	**165**	$	141
Current liability		**12**		6
Long-term liability		**153**		135
Asset retirement obligation at December 31	**$**	**165**	$	141

(1) Obligations settled/removed include $35 million related to asset divestitures in 2016.

(11) RETIREMENT AND EMPLOYEE BENEFIT PLANS

401(k) Defined Contribution Plan

The Company has a 401(k) defined contribution plan covering eligible employees. The Company expensed $3 million, $4 million and $3 million of contribution expense in 2017, 2016 and 2015, respectively. Additionally, the Company capitalized $2 million, $2 million and $4 million of contributions in 2017, 2016 and 2015, respectively, directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties or directly related to the construction of the Company's gathering systems.

Defined Benefit Pension and Other Postretirement Plans

Prior to January 1, 1998, the Company maintained a traditional defined benefit plan with benefits payable based upon average final compensation and years of service. Effective January 1, 1998, the Company amended its pension plan to become a "cash balance" plan on a prospective basis for its non-bargaining employees. A cash balance plan provides benefits based upon a fixed percentage of an employee's annual compensation. The Company's funding policy is to contribute amounts which are actuarially determined to provide the plans with sufficient assets to meet future benefit payment requirements and which are tax deductible.

The postretirement benefit plan provides contributory health care and life insurance benefits. Employees become eligible for these benefits if they meet age and service requirements. Generally, the benefits paid are a stated percentage of medical expenses reduced by deductibles and other coverages.

Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. The Company accounts for its defined benefit pension and other postretirement plans by recognizing the funded status of each defined pension benefit plan and other postretirement benefit plan on the Company's balance sheet. In the event a plan is overfunded, the Company recognizes an asset. Conversely, if a plan is underfunded, the Company recognizes a liability.

In January 2016, the Company initiated a reduction in workforce that was effectively completed by the end of the first quarter. As a result of the workforce reduction, the Company recognized a $1 million non-cash curtailment loss related to its pension plan for both the curtailment-related decrease to the benefit obligation and the recognition of the proportionate share of unrecognized prior service cost and net loss from other comprehensive income (loss) in the second quarter of 2016. For the year ended December 31, 2016, the Company recognized a non-cash settlement loss of $11 million related to a total of $37 million of lump sum payments from the pension plan. Additionally, the Company recognized a non-cash curtailment gain of $6 million related to its other postretirement benefit plan in the first quarter of 2016.

The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets and funded status as of December 31, 2017 and 2016:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2017**	2016	**2017**	2016
Change in benefit obligations:				
Benefit obligation at January 1	**$ 117**	$ 138	**$ 13**	$ 20
Service cost	**9**	11	**2**	2
Interest cost	**5**	5	**–**	1
Participant contributions	**–**	–	**–**	–
Actuarial loss (gain)	**21**	14	**3**	(2)
Benefits paid	**(9)**	(3)	**(1)**	(1)
Plan amendments	**–**	–	**–**	–
Curtailments	**–**	(8)	**–**	(7)
Settlements	**–**	(40)	**–**	–
Benefit obligation at December 31	**$ 143**	**$** 117	**$ 17**	**$** 13

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2017**	2016	**2017**	2016
Change in plan assets:				
Fair value of plan assets at January 1	**$ 81**	$ 108	**$ –**	$ –
Actual return on plan assets	**15**	3	**–**	–
Employer contributions	**14**	10	**1**	1
Participant contributions	**–**	–	**–**	–
Benefits paid	**(9)**	(3)	**(1)**	(1)
Settlements	**–**	(37)	**–**	–
Fair value of plan assets at December 31	**$ 101**	$ 81	**$ –**	$ –
Funded status of plans at December 31	**$ (42)**	$ (36)	**$ (17)**	$ (13)

The Company uses a December 31 measurement date for all of its plans and had liabilities recorded for the underfunded status for each period as presented above.

The pension plans' projected benefit obligation, accumulated benefit obligation and fair value of plan assets as of December 31, 2017 and 2016 are as follows:

(in millions)	**2017**	2016
Projected benefit obligation	**$ 143**	$ 117
Accumulated benefit obligation	**137**	116
Fair value of plan assets	**101**	81

Pension and other postretirement benefit costs include the following components for 2017, 2016 and 2015:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2017**	2016	2015	**2017**	2016	2015
Service cost	**$ 9**	$ 11	$ 16	**$ 2**	$ 2	$ 3
Interest cost	**5**	5	6	**–**	1	1
Expected return on plan assets	**(6)**	(6)	(9)	**–**	–	–
Amortization of transition obligation	**–**	–	–	**–**	–	–
Amortization of prior service cost	**–**	–	–	**–**	–	–
Amortization of net loss	**2**	2	2	**–**	–	–
Net periodic benefit cost	**10**	12	15	**2**	3	4
Curtailment loss	**–**	1	–	**–**	(6)	–
Settlement loss	**–**	11	–	**–**	–	–
Total benefit cost (benefit)	**$ 10**	$ 24	$ 15	**$ 2**	$ (3)	$ 4

Amounts recognized in other comprehensive income for the years ended December 31, 2017 and 2016 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2017**	2016	**2017**	2016
Net actuarial (loss) gain arising during the year	**$ (11)**	$ (13)	**$ (2)**	$ 2
Amortization of prior service cost	**–**	–	**–**	–
Amortization of net loss	**2**	20	**–**	–
Settlements	**–**	–	**–**	1
Tax effect [(1)]	**3**	(3)	**1**	(1)
	$ (6)	$ 4	**$ (1)**	$ 2

(1) Deferred tax activity related to pension and other postretirement benefits was offset by a valuation allowance, resulting in no tax expense recorded for the period.

Included in accumulated other comprehensive income as of December 31, 2017 and 2016 was a $42 million loss ($26 million net of tax) and a $31 million loss ($19 million net of tax), respectively, related to the Company's pension and other postretirement benefit plans. For the year ended December 31, 2017, $7 million was classified to accumulated other comprehensive income, primarily driven by actuarial loss adjustments. Amortization of prior period service cost reclassified from accumulated other comprehensive income to general and administrative expenses for the year was immaterial.

The amount in accumulated other comprehensive income that is expected to be recognized as a component of net periodic benefit cost during 2018 is a $2 million net loss.

The assumptions used in the measurement of the Company's benefit obligations as of December 31, 2017 and 2016 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	**2017**	2016
Discount rate	**3.75 %**	4.20 %	**3.75 %**	4.20 %
Rate of compensation increase	**3.50 %**	3.50 %	**n/a**	n/a %

The assumptions used in the measurement of the Company's net periodic benefit cost for 2017, 2016 and 2015 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2017	2016	2015	**2017**	2016	2015
Discount rate	**4.20 %**	4.20 %	4.25 %	**4.20 %**	4.20 %	4.25 %
Expected return on plan assets	**7.00 %**	7.00 %	7.00 %	**n/a**	n/a	n/a
Rate of compensation increase	**3.50 %**	3.50 %	4.50 %	**n/a**	n/a	n/a

The expected return on plan assets for the various benefit plans is based upon a review of the historical returns experienced, combined with the future expected returns based upon the asset allocation strategy employed. The plans seek to achieve an adequate return to fund the obligations in a manner consistent with the federal standards of the Employee Retirement Income Security Act and with a prudent level of diversification.

For measurement purposes, the following trend rates were assumed for 2017 and 2016:

	2017	2016
Health care cost trend assumed for next year	7%	7%
Rate to which the cost trend is assumed to decline	5%	5%
Year that the rate reaches the ultimate trend rate	2035	2034

Assumed health care cost trend rates have a significant effect on the amounts for the health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

(in millions)	1% Increase	1% Decrease
Effect on the total service and interest cost components	$ –	$ –
Effect on postretirement benefit obligations	$ 3	$ (2)

Pension Payments and Asset Management

In 2017, the Company contributed $14 million to its pension plans and $1 million to its other postretirement benefit plan. The Company expects to contribute $13 million to its pension and other postretirement benefit plans in 2018.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Pension Benefits		Other Postretirement Benefits	
	(in millions)		
2018	$ 6	2018	$ 1
2019	6	2019	1
2020	7	2020	1
2021	8	2021	1
2022	8	2022	1
Years 2023-2027	52	Years 2023-2027	7

The Company's overall investment strategy is to provide an adequate pool of assets to support both the long-term growth of plan assets and to ensure adequate liquidity exists for the near-term payment of benefit obligations to participants, retirees and beneficiaries. The Benefits Administration Committee of the Company, appointed by the Compensation Committee of the Board of Directors, administers the Company's pension plan assets. The Benefits Administration Committee believes long-term investment performance is a function of asset-class mix and restricts the composition of pension plan assets to a combination of cash and cash equivalents, domestic equity markets, international equity markets or investment grade fixed income assets.

The table below presents the allocations targeted by the Benefits Administration Committee and the actual weighted-average asset allocation of the Company's pension plan as of December 31, 2017, by asset category. The asset allocation targets are subject to change and the Benefits Administration Committee allows for its actual allocations to deviate from target as a result of current and anticipated market conditions. Plan assets are periodically balanced whenever the allocation to any asset class falls outside of the specified range.

	Pension Plan Asset Allocations	
Asset category:	Target	Actual
Equity securities:		
U.S. Equity (1)	35 %	36 %
Non-U.S. Developed Equity (2)	30 %	30 %
Emerging Markets Equity (3)	5 %	5 %
Opportunistic (4)	– %	– %
Fixed income (5)	28 %	27 %
Cash (6)	2 %	2 %
Total	100 %	100 %

(1) Includes the following equity securities in the table below: U.S. large cap growth equity, U.S. large cap value equity, U.S. large cap core equity, and U.S. small cap equity.

(2) Includes Non-U.S. equity securities in the table below.
(3) Includes emerging markets equity securities below.
(4) Includes none of the securities in the table below.
(5) Includes fixed income pension plan assets in the table below.
(6) Includes Cash and cash equivalents pension plan assets in the table below.

Utilizing the fair value hierarchy described in Note 6 – Fair Value Measurements, the Company's fair value measurement of pension plan assets as of December 31, 2017 is as follows:

(in millions)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Measured within fair value hierarchy				
Equity securities:				
U.S. large cap growth equity (1)	$ 7	$ 7	$ –	$ –
U.S. large cap value equity (2)	8	8	–	–
U.S. small cap equity (3)	3	3	–	–
Non-U.S. equity (4)	30	30	–	–
Emerging markets equity (5)	5	5	–	–
Fixed income (6)	27	27	–	–
Cash and cash equivalents	3	3	–	–
Total measured within fair value hierarchy	$ 83	$ 83	$ –	$ –
Measured at net asset value (7)				
Equity securities:				
U.S. large cap core equity (8)	18			
Total measured at net asset value	$ 18			
Total plan assets at fair value	$ 101			

Utilizing the fair value hierarchy described in Note 6 – Fair Value Measurements, the Company's fair value measurement of pension plan assets at December 31, 2016 was as follows:

(in millions)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Measured within fair value hierarchy				
Equity securities:				
U.S. large cap growth equity (1)	$ 6	$ 6	$ –	$ –
U.S. large cap value equity (2)	6	6	–	–
U.S. small cap equity (3)	3	3	–	–
Non-U.S. equity (4)	23	23	–	–
Emerging markets equity (5)	4	4	–	–
Fixed income (6)	21	21	–	–
Cash and cash equivalents	4	4	–	–
Total measured within fair value hierarchy	$ 67	$ 67	$ –	$ –
Measured at net asset value (7)				
Equity securities:				
U.S. large cap core equity (8)	14			
Total measured at net asset value	$ 14			
Total plan assets at fair value	$ 81			

(1) Mutual fund that seeks to invest in a diversified portfolio of stocks with price appreciation growth opportunities.
(2) Mutual fund that seeks to invest in a diversified portfolio of stocks that will increase in value over the long-term as well as provide current income.
(3) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
(4) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.
(5) An institutional fund that invests primarily in the equity securities of companies domiciled in emerging markets.
(6) Institutional funds that seek an investment return that approximates, as closely as practicable, before expenses, the performance of the Barclays U.S. Intermediate Credit Bond Index over the long term and the Barclays Long U.S. Corporate Bond Index over the long-term.
(7) Plan assets for which fair value was measured using net asset value as a practical expedient.
(8) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.

The Company's pension plan assets that are classified as Level 1 are the investments comprised of either cash or investments in open-ended mutual funds which produce a daily net asset value that is validated with a sufficient level of observable activity to support classification of the fair value measurement as Level 1. Due to the Company's implementation of Accounting Standards Update No. 2015-07, assets measured using net asset value as a practical expedient have not been classified in the fair value hierarchy. No concentration of risk arising within or across categories of plan assets exists due to any significant investments in a single entity, industry, country or investment fund.

(12) STOCK-BASED COMPENSATION

The Southwestern Energy Company 2013 Incentive Plan was adopted in February 2013, approved by stockholders in May 2013 and amended and restated per stockholders' approval in May 2016 and further amended in May 2017 (the "2013 Plan"). The 2013 Plan provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries.

The 2013 Plan provides for grants of options, stock appreciation rights, and shares of restricted stock and restricted stock units to employees, officers and directors that, in the aggregate, do not exceed 52,700,000 shares. The types of incentives that may be awarded are comprehensive and are intended to enable the Company's board of directors to structure the most appropriate incentives and to address changes in income tax laws which may be enacted over the term of the 2013 Plan.

The Company measures the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. All options are issued at fair market value at the date of grant and expire seven years from the date of grant. Generally, stock options granted to employees and directors vest ratably over three years from the grant date. The Company issues shares of restricted stock to employees and directors which generally vest over four years. The Company recognizes stock-based compensation expense on a straight-line basis over the requisite service period of the individual grants with the exception of awards granted to participants who have reached retirement age or will reach retirement age during the vesting period. Restricted stock and stock options granted to participants under the 2013 Plan immediately vest upon death, disability or retirement (subject to a minimum of three years of service).

In January 2016, the Company announced a 40% workforce reduction that was substantially concluded by the end of March 2016. In April 2016, the Company also partially restructured executive management, which was substantially completed in the second quarter of 2016. Affected employees were offered a severance package that included, if applicable, amendments to certain outstanding equity awards that modified forfeiture provisions upon separation from the Company. As a result, certain unvested stock-based equity awards became fully vested at the time of separation. These shares were revalued and recognized immediately as a component of restructuring charges on the Company's consolidated statement of operations. The unvested portion of equity-based performance units was forfeited upon separation from the Company.

Stock Options

The Company recorded the following compensation costs related to stock options for the years ended December 31, 2017, 2016 and 2015:

(in millions)	**2017**	2016	2015
Stock options – general and administrative expense (1)	**$ 3**	$ 6	$ 5
Stock options – general and administrative expense capitalized	**$ 1**	$ 1	$ 3

(1) Includes less than $1 million related to the reduction in workforce and $1 million related to executive management restructuring for the year ended December 31, 2016.

The Company also recorded a deferred tax asset of $1 million, $2 million and $2 million related to stock options in 2017, 2016 and 2015, respectively. Unrecognized compensation cost related to the Company's unvested stock options totaled $4 million at December 31, 2017. This cost is expected to be recognized over a weighted-average period of 2 years.

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's common stock and other factors. The Company uses historical data on the exercise of stock options, post-vesting forfeitures and other factors to estimate the expected term of the stock-based payments granted. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant.

Assumptions	2017	2016	2015
Risk-free interest rate	**1.9%**	1.4%	1.7%
Expected dividend yield	**–**	–	–
Expected volatility	**50.5%**	41.0%	36.0%
Expected term	**5 years**	5 years	5 years

The following tables summarize stock option activity for the years 2017, 2016 and 2015, and provide information for options outstanding at December 31 of each year:

	2017		2016		2015	
	Number of Shares	**Weighted Average Exercise Price**	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
	(in thousands)		*(in thousands)*		*(in thousands)*	
Options outstanding at January 1	**5,416**	**$ 23.46**	5,623	$ 24.57	3,622	$ 35.41
Granted [(1)]	**1,604**	**8.00**	155	8.60	2,401	9.47
Exercised	**–**	**–**	(45)	7.74	–	–
Forfeited or expired	**(1,000)**	**22.93**	(317)	38.01	(400)	32.20
Options outstanding at December 31	**6,020**	**$ 19.43**	5,416	$ 23.46	5,623	$ 24.57

(1) Shares granted in 2016 are considerably lower than historical norms. In 2016, the Company changed the grant date of its annual stock option awards from December to the following February.

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Options Outstanding at December 31, 2017	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable at December 31, 2017	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
	(in thousands)		*(years)*	*(in thousands)*		*(years)*
$5.22-$29.42	**3,614**	**8.85**	5.4	1,487	9.52	4.8
$30.59-$35.91	**1,252**	**32.35**	2.9	1,252	32.35	2.9
$36.22-$39.68	**1,046**	**37.77**	1.8	1,046	37.77	1.8
$40.15-$51.47	**108**	**45.92**	2.9	108	45.92	2.9
	6,020	**$ 19.43**	4.2	3,893	$ 25.46	3.3

The weighted-average grant date fair value of options granted during the years 2017, 2016 and 2015 was $3.47, $3.22 and $3.16, respectively. There were no options exercised in 2017. The total intrinsic value of options exercised during 2016 was less than $1 million. There were no options exercised in 2015.

Restricted Stock

The Company recorded the following compensation costs related to restricted stock grants for the years ended December 31, 2017, 2016 and 2015:

(in millions)	**2017**	2016	2015
Restricted stock grants – general and administrative expense [(1)]	**$ 16**	$ 33	$ 14
Restricted stock grants – general and administrative expense capitalized	**$ 11**	$ 8	$ 16

(1) Includes $16 million related to the reduction in workforce and $1 million related to executive management restructuring for the year ended December 31, 2016.

The Company also recorded a deferred tax asset of $9 million related to restricted stock for the year ended December 31, 2017, compared to a deferred tax assets of $12 million and $11 million for 2016 and 2015, respectively. As of December 31, 2017, there was $45 million of total unrecognized compensation cost related to unvested shares of restricted stock that is expected to be recognized over a weighted-average period of 3 years.

The following table summarizes the restricted stock activity for the years 2017, 2016 and 2015, and provides information for restricted stock outstanding at December 31 of each year:

	2017		2016		2015	
	Number of Shares *(in thousands)*	**Weighted Average Fair Value**	Number of Shares *(in thousands)*	Weighted Average Fair Value	Number of Shares *(in thousands)*	Weighted Average Fair Value
Unvested shares at January 1	**3,321**	**$ 11.85**	7,222	$ 13.24	2,376	$ 34.00
Granted (1)	**5,055**	**8.38**	81	8.56	5,822	8.07
Vested (2)	**(1,380)**	**13.28**	(3,817)	11.34	(873)	33.33
Forfeited	**(742)**	**10.04**	(165)	12.05	(103)	29.14
Unvested shares at December 31	**6,254**	**$ 8.85**	3,321	$ 11.85	7,222	$ 13.24

(1) Shares granted in 2016 were considerably lower than historical norms. In 2016, the Company changed the grant date of its annual restricted stock awards from December to the following February.

(2) Includes 2,059,626 shares and 151,575 shares related to reduction in workforce and executive management restructuring, respectively, for the year ended December 31, 2016.

The fair values of the grants were $42 million for 2017, $1 million for 2016 and $47 million for 2015. The total fair value of shares vested were $18 million for 2017, $43 million for 2016 and $29 million for 2015.

Equity-Classified Performance Units

The Company recorded compensation costs related to equity-classified performance units for the years ended December 31, 2017, 2016 and 2015. The performance units awarded in 2017, 2016 and 2015 included a market condition based on relative Total Shareholder Return ("TSR"). The grant date fair value is calculated using the closing price of the Company's common stock at the grant date and a Monte Carlo model to estimate the TSR market condition. The estimated fair value is amortized to compensation expense on a straight-line basis over the vesting period of the award.

(in millions)	**2017**	2016	2015
Performance units – general and administrative expense (1)	**$ 5**	$ 9	$ 6
Performance units – general and administrative expense capitalized	**$ 2**	$ 1	$ 4

(1) Includes less than $1 million related to reduction in workforce and $1 million related to executive management restructuring for the year ended December 31, 2016.

The Company also recorded a deferred tax asset of $3 million related to equity-based performance units for the year ended December 31, 2017, compared to deferred tax assets of $4 million and $4 million in 2016 and 2015, respectively. As of December 31, 2017, there was $8 million of total unrecognized compensation cost related to unvested equity-based performance units that is expected to be recognized over a weighted-average period of 2 years.

The following table summarizes performance unit activity to be paid out in Company stock for the years ended December 31, 2017, 2016 and 2015, and provides information for unvested units as of December 31, 2017, 2016 and 2015:

	2017		2016		2015	
	Number of Units (1) *(in thousands)*	**Weighted Average Fair Value**	Number of Units (1) *(in thousands)*	Weighted Average Fair Value	Number of Units (1) *(in thousands)*	Weighted Average Fair Value
Unvested shares at January 1	**719**	**$ 11.46**	407	$ 36.65	223	$ 40.44
Granted	**1,197**	**10.47**	1,503	8.60	443	35.22
Vested (2)	**(325)**	**12.21**	(889)	12.78	(259)	37.46
Forfeited (3)	**(507)**	**9.53**	(302)	11.26	–	–
Unvested shares at December 31	**1,084**	**$ 10.12**	719	$ 11.46	407	$ 36.65

(1) These amounts reflect the number of performance units granted in thousands. The actual payout in shares may range from a minimum of zero shares to a maximum of two shares contingent upon the actual performance against the Performance Measures. The performance units have a three-year vesting term and the actual disbursement of shares, if any, is not determined until March following the end of the three-year vesting period.

(2) Includes 22,918 units and 37,590 units related to the reduction in workforce and executive management restructuring, respectively, for the year ended December 31, 2016.

(3) Includes 87,595 units and 195,834 units related to the reduction in workforce and executive management restructuring, respectively, for the year ended December 31, 2016.

Liability-Classified Performance Units

Prior to 2013, certain employees were provided performance units vesting equally over three years that were settled in cash. The payout of these units was based on certain metrics, such as total shareholder return and reserve replacement efficiency, compared to a predetermined group of peer companies and Company goals. At the end of each performance period, the value of the vested performance units, if any, would be paid in cash. In the first quarter of 2016, the Company completed the final payout under these performance unit agreements.

(13) SEGMENT INFORMATION

The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and liquids. The Midstream segment generates revenue through the marketing of both Company and third-party produced natural gas and liquids volumes and through gathering fees associated with the transportation of natural gas to market.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1 – Organization and Summary of Significant Accounting Policies. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense, gain (loss) on derivatives, loss on early extinguishment of debt and other income (loss). The "Other" column includes items not related to the Company's reportable segments, including real estate and corporate items.

(in millions)	Exploration and Production	Midstream	Other	Total
2017				
Revenues from external customers	**$ 2,105**	**$ 1,098**	**$ –**	**$ 3,203**
Intersegment revenues	**(19)**	**2,100**	**–**	**2,081**
Depreciation, depletion and amortization expense	**440**	**64**	**–**	**504**
Operating income (loss)	**549**	**183**	**(1)**	**731**
Interest expense (1)	**135**	**–**	**–**	**135**
Gain on derivatives	**421**	**1**	**–**	**422**
Loss on early extinguishment of debt	**–**	**–**	**(70)**	**(70)**
Other income, net	**4**	**1**	**–**	**5**
Benefit for income taxes (1)	**(93)**	**–**	**–**	**(93)**
Assets	**5,109** (2)	**1,288**	**1,124** (3)	**7,521**
Capital investments (4)	**1,248**	**32**	**13**	**1,293**
2016				
Revenues from external customers	$ 1,435	$ 1,001	$ –	$ 2,436
Intersegment revenues	(22)	1,568	–	1,546
Depreciation, depletion and amortization expense	371	65	–	436
Impairment of natural gas and oil properties	2,321	–	–	2,321
Operating income (loss)	(2,404) (5)	209 (6)	–	(2,195)
Interest expense (1)	87	1	–	88
Loss on derivatives	(338)	(1)	–	(339)
Loss on early extinguishment of debt	–	–	(51)	(51)
Other income (loss), net	5	(2)	(2)	1
Benefit for income taxes (1)	(29)	–	–	(29)
Assets	4,178 (2)	1,331	1,567 (3)	7,076
Capital investments (4)	623	21	4	648
2015				
Revenues from external customers	$ 2,095	$ 1,038	$ –	$ 3,133
Intersegment revenues	(21)	2,081	–	2,060
Depreciation, depletion and amortization expense	1,028	62	1	1,091
Impairment of natural gas and oil properties	6,950	–	–	6,950
Operating income (loss)	(7,104)	583 (7)	(1)	(6,522)
Interest expense (1)	47	9	–	56
Gain (loss) on derivatives	51	–	(4)	47
Other loss, net	(21)	(9)	–	(30)
Provision (benefit) for income taxes (1)	(2,273)	268	–	(2,005)
Assets	6,588 (2)	1,290	208 (3)	8,086
Capital investments (4)	2,258	167	12	2,437

(1) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as they are incurred at the corporate level.

(2) Includes office, technology, water infrastructure, drilling rigs and other ancillary equipment not directly related to natural gas and oil property acquisition, exploration and development activities.

(3) Other assets represent corporate assets not allocated to segments and assets for non-reportable segments. At December 31, 2017, other assets includes approximately $916 million in cash and cash equivalents.

(4) Capital investments include an increase of $43 million for 2016 and a decrease of $33 million for 2015 related to the change in accrued expenditures between years. There was no impact to 2017.

(5) Operating loss for the E&P segment includes $86 million related to restructuring and other one-time charges for the year ended December 31, 2016.

(6) Operating income for the Midstream segment includes $3 million related to restructuring charges for the year ended December 31, 2016.

(7) Operating income (loss) for the Midstream segment includes a $277 million gain on sale of assets for the year ended December 31, 2015.

Included in intersegment revenues of the Midstream segment are $1.9 billion, $1.3 billion and $1.8 billion for 2017, 2016 and 2015, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments.

SUPPLEMENTAL QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2017 and 2016:

(in millions, except per share amounts)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
		2017		
Operating revenues	**$ 846**	**$ 811**	**$ 737**	**$ 809**
Operating income	**266**	**188**	**110**	**167**
Net income attributable to common stock	**281**	**224**	**43**	**267**
Earnings per share - Basic	**0.57**	**0.45**	**0.09**	**0.53**
Earnings per share - Diluted	**0.57**	**0.45**	**0.09**	**0.53**
		2016		
Operating revenues	$ 579	$ 522	$ 651	$ 684
Operating income (loss) [(1)]	(1,100)	(492)	(725)	122
Net loss attributable to common stock	(1,159)	(620)	(735)	(237)
Loss per share - Basic	(3.03)	(1.61)	(1.52)	(0.48)
Loss per share - Diluted	(3.03)	(1.61)	(1.52)	(0.48)

(1) The operating losses for the first, second and third quarters of 2016 included non-cash full cost impairments of natural gas and oil properties of $1,034 million, $470 million, and $817 million, respectively. There was no full cost impairment in the fourth quarter of 2016 and for the year ended December 31, 2017.

SUPPLEMENTAL OIL AND GAS DISCLOSURES (UNAUDITED)

The Company's operating natural gas and oil properties are located solely in the United States. The Company also has licenses to properties in Canada, the development of which is subject to an indefinite moratorium. See "Our Operations — Other — New Brunswick, Canada" in Item 1 of Part 1 of this Annual Report.

Net Capitalized Costs

The following table shows the capitalized costs of natural gas and oil properties and the related accumulated depreciation, depletion and amortization as of December 31, 2017 and 2016:

(in millions)	**2017**	2016
Proved properties	**$ 22,073**	$ 20,548
Unproved properties	**1,817**	2,105
Total capitalized costs	**23,890**	22,653
Less: Accumulated depreciation, depletion and amortization	**(19,287)**	(18,897)
Net capitalized costs	**$ 4,603**	$ 3,756

Natural gas and oil properties not subject to amortization represent investments in unproved properties and major development projects in which the Company owns an interest. These unproved property costs include unevaluated costs associated with leasehold or drilling interests and unevaluated costs associated with wells in progress. The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2017:

(in millions)	2017	2016	2015	Prior	**Total**
Property acquisition costs	$ 80	$ 18	$ 145	$ 1,295	**$ 1,538**
Exploration and development costs	67	7	32	14	**120**
Capitalized interest	67	41	33	18	**159**
	$ 214	$ 66	$ 210	$ 1,327	**$ 1,817**

Of the total net unevaluated costs excluded from amortization as of December 31, 2017, approximately $1.5 billion is related to the acquisition of undeveloped properties in Southwest Appalachia, approximately $90 million is related to the acquisition of the Company's undeveloped properties in Northeast Appalachia and approximately $16 million is related to the acquisition of undeveloped properties outside the Appalachian Basin and the Fayetteville Shale. Additionally, the Company has approximately $159 million of unevaluated capitalized interest and $88 million of unevaluated costs related to wells in progress. The remaining costs excluded from amortization are related to properties which are not individually significant and on which the evaluation process has not been completed. The timing and amount of property acquisition and seismic costs included in the amortization computation will depend on the location and timing of drilling wells, results of drilling and other assessments. The Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

Costs Incurred in Natural Gas and Oil Exploration and Development

The table below sets forth capitalized costs incurred in natural gas and oil property acquisition, exploration and development activities:

(in millions, except per Mcfe amounts)	**2017**	2016	2015
Proved property acquisition costs	**$ –**	$ –	$ 81
Unproved property acquisition costs	**194**	171	692
Exploration costs	**22**	17	50
Development costs	**1,024**	433	1,417
Capitalized costs incurred	**1,240**	621	2,240
Full cost pool amortization per Mcfe	**$ 0.45**	$ 0.38	$ 1.00

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $113 million, $152 million and $204 million during 2017, 2016 and 2015, respectively, based on the Company's weighted average cost of borrowings used to finance expenditures.

In addition to capitalized interest, the Company capitalized internal costs totaling $99 million, $87 million and $175 million during 2017, 2016 and 2015, respectively, which were directly related to the acquisition, exploration and development of the Company's natural gas and oil properties.

Results of Operations from Natural Gas and Oil Producing Activities

The table below sets forth the results of operations from natural gas and oil producing activities:

(in millions)	**2017**	2016	2015
Sales	**$ 2,086**	$ 1,413	$ 2,074
Production (lifting) costs	**(891)**	(839)	(989)
Depreciation, depletion and amortization	**(440)**	(371)	(1,028)
Impairment of natural gas and oil properties	**–**	(2,321)	(6,950)
	755	(2,118)	(6,893)
Provision (benefit) for income taxes (1)	**–**	–	(2,619)
Results of operations (2)	**$ 755**	$ (2,118)	$ (4,274)

(1) Prior to the recognition of a valuation allowance, in 2017 and 2016 the Company recognized income tax provisions of $287 million and $805 million, respectively.

(2) Results of operations exclude the gain (loss) on unsettled commodity derivative instruments. See Note 4 - Derivatives and Risk Management

The results of operations shown above exclude general and administrative expenses and interest expense and are not necessarily indicative of the contribution made by the Company's natural gas and oil operations to its consolidated operating results. Income tax expense is calculated by applying the statutory tax rates to the revenues less costs, including depreciation, depletion and amortization, and after giving effect to permanent differences and tax credits.

Natural Gas and Oil Reserve Quantities

The Company engaged the services of Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm, to audit the reserves estimated by the Company's reservoir engineers. In conducting its audit, the engineers and geologists of NSAI studied the Company's major properties in detail and independently developed reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of the Company's major properties, and accounted for approximately 99%, 99% and 100% of the present worth of the Company's total proved reserves as of December 31, 2017, 2016 and 2015, respectively. A reserve audit is not the same as a financial audit, and a reserve audit is less rigorous in nature than a reserve report prepared by an independent petroleum engineering firm containing its own estimate of reserves. Reserve estimates are inherently imprecise, and the Company's reserve estimates are generally based upon extrapolation of historical production trends, historical prices of natural gas and crude oil and analogy to similar properties and volumetric calculations. Accordingly, the Company's estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available. For more information over reserves, refer to the table titled "Changes in Proved Undeveloped Reserves (Bcfe)" in "Business – Exploration and Production" in Item 1 of this Annual Report.

The following table summarizes the changes in the Company's proved natural gas, oil and NGL reserves for 2017, 2016 and 2015, all of which were located in the United States:

	Natural Gas *(Bcf)*	Oil *(MBbls)*	NGL *(MBbls)*	**Total** ***(Bcfe)***
December 31, 2014	**9,809**	**37,615**	**118,699**	**10,747**
Revisions of previous estimates [(1)]	(3,458)	(28,394)	(75,664)	**(4,083)**
Extensions, discoveries and other additions	546	1,367	6,274	**592**
Production	(899)	(2,265)	(10,702)	**(976)**
Acquisition of reserves in place	97	525	2,340	**115**
Disposition of reserves in place	(178)	(95)	–	**(180)**
December 31, 2015	**5,917**	**8,753**	**40,947**	**6,215**
Revisions of previous estimates	(446)	1,564	13,794	**(354)**
Extensions, discoveries and other additions	198	2,417	11,576	**282**
Production	(788)	(2,192)	(12,372)	**(875)**
Acquisition of reserves in place	–	–	–	**–**
Disposition of reserves in place	(15)	(19)	(14)	**(15)**
December 31, 2016	**4,866**	**10,523**	**53,931**	**5,253**
Revisions of previous estimates	1,898	1,668	70,549	**2,332**
Extensions, discoveries and other additions [(2)]	5,159	55,772	432,220	**8,087**
Production	(797)	(2,327)	(14,245)	**(897)**
Acquisition of reserves in place	–	–	–	**–**
Disposition of reserves in place	–	–	–	**–**
December 31, 2017	**11,126**	**65,636**	**542,455**	**14,775**

(1) The significant revisions of previous estimates in 2015 was primarily due to price revision, as a result of lower average commodity prices in 2015.

(2) The 2017 PUD additions are primarily associated with the increase in commodity prices.

	Natural Gas *(Bcf)*	Oil *(MBbls)*	NGL *(MBbls)*	**Total** ***(Bcfe)***
Proved developed reserves as of:				
December 31, 2015	5,474	8,753	40,947	**5,772**
December 31, 2016	4,789	10,523	53,931	**5,176**
December 31, 2017	**6,979**	**14,513**	**142,213**	**7,920**
Proved undeveloped reserves as of:				
December 31, 2015	443	–	–	**443**
December 31, 2016	77	–	–	**77**
December 31, 2017	**4,147**	**51,123**	**400,242**	**6,855**

The Company's estimated proved natural gas, oil and NGL reserves were 14,775 Bcfe at December 31, 2017, compared to 5,253 Bcfe at December 31, 2016. The increase in the Company's reserves in 2017, compared to 2016, primarily resulted through extensions, discoveries and other additions in the Appalachian Basin along with increases in both price and performance revisions across the portfolio. The decrease in the Company's reserves in 2016 was primarily due to the decrease in commodity prices. The significant decrease in the Company's reserves in 2015 was primarily due to the decrease in commodity prices.

The following table summarizes the changes in reserves for 2015, 2016 and 2017:

	Appalachia		Fayetteville		
(in Bcfe)	Northeast	Southwest	Shale	Other (1)	**Total**
December 31, 2014	**3,191**	**2,297**	**5,069**	**190**	**10,747**
Net revisions					
Price revisions	(2,315)	(1,875)	(1,496)	(32)	**(5,718)**
Performance and production revisions	1,383	209	10	33	**1,635**
Total net revisions	(932)	(1,666)	(1,486)	1	**(4,083)**
Extensions, discoveries and other additions					
Proved developed	202	84	129	1	**416**
Proved undeveloped	138	4	34	–	**176**
Total reserve additions	340	88	163	1	**592**
Production	(360)	(143)	(465)	(8)	**(976)**
Acquisition of reserves in place	80	35	–	–	**115**
Disposition of reserves in place	–	–	–	(180)	**(180)**
December 31, 2015	**2,319**	**611**	**3,281**	**4**	**6,215**
Net revisions					
Price revisions	(794)	(127)	(116)	–	**(1,037)**
Performance and production revisions	318	199	163	3	**683**
Total net revisions	(476)	72	47	3	**(354)**
Extensions, discoveries and other additions					
Proved developed	81	157	19	–	**257**
Proved undeveloped	–	–	25	–	**25**
Total reserve additions	81	157	44	–	**282**
Production	(350)	(148)	(375)	(2)	**(875)**
Acquisition of reserves in place	–	–	–	–	**–**
Disposition of reserves in place	–	(15)	–	–	**(15)**
December 31, 2016	**1,574**	**677**	**2,997**	**5**	**5,253**
Net revisions					
Price revisions	903	738	49	1	**1,691**
Performance and production revisions	154	125	358	4	**641**
Total net revisions	1,057	863	407	5	**2,332**
Extensions, discoveries and other additions					
Proved developed	790	419	48	1	**1,258**
Proved undeveloped	1,100	5,186	543	–	**6,829**
Total reserve additions	1,890	5,605	591	1	**8,087**
Production	(395)	(183)	(316)	(3)	**(897)**
Acquisition of reserves in place	–	–	–	–	**–**
Disposition of reserves in place	–	–	–	–	**–**
December 31, 2017	**4,126**	**6,962**	**3,679**	**8**	**14,775**

(1) Other includes properties outside of the Appalachian Basin and Fayetteville Shale along with Ark-La-Tex properties divested in May 2015.

The Company's December 31, 2017 proved reserves included 1,375 Bcfe of proved undeveloped reserves from 330 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but do not have a positive present value when discounted at 10%. These properties had a negative present value of $124 million when discounted at 10%. The Company made a final investment decision and is committed to developing these reserves within the next five years from the date of initial booking.

The Company's December 31, 2016 proved reserves included 77 Bcfe of proved undeveloped reserves from 15 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but that have a negative $11 million present value when discounted at 10%. The Company's December 31, 2015 proved reserves included 217 Bcfe of proved undeveloped reserves from 75 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but that have a negative $34 million present value when discounted at 10%.

The Company has no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. The Company used standard engineering and geoscience methods, or a combination of methodologies in determining estimates of material properties, including performance and test date analysis, offset statistical analogy of performance data, volumetric evaluation, including analysis of petrophysical parameters (including porosity, net pay, fluid saturations (i.e., water, oil and gas) and permeability) in combination with estimated reservoir parameters (including reservoir temperature and pressure, formation depth and formation volume factors), geological analysis, including structure and isopach maps and seismic analysis, including review of 2-D and 3-D data to ascertain faults, closure and other factors.

Standardized Measure of Discounted Future Net Cash Flows

The following standardized measures of discounted future net cash flows relating to proved natural gas, oil and NGL reserves as of December 31, 2017, 2016 and 2015 are calculated after income taxes, discounted using a 10% annual discount rate and do not purport to present the fair market value of the Company's proved gas, oil and NGL reserves:

(in millions)	**2017**	2016	2015
Future cash inflows	**$ 36,576**	$ 9,064	$ 11,887
Future production costs	**(18,390)**	(5,880)	(7,376)
Future development costs [(1)]	**(4,676)**	(485)	(792)
Future income tax expense [(2)]	**(1,342)**	–	–
Future net cash flows	**12,168**	2,699	3,719
10% annual discount for estimated timing of cash flows	**(6,606)**	(1,034)	(1,302)
Standardized measure of discounted future net cash flows	**$ 5,562**	$ 1,665	$ 2,417

(1) Includes abandonment costs.

(2) The December 31, 2016 and 2015 standardized measure computation does not have future income taxes because the Company's tax basis in the associated oil and gas properties exceeded expected pre-tax cash inflows. Future net cash flows are not permitted to be increased by excess tax basis.

Under the standardized measure, future cash inflows were estimated by applying an average price from the first day of each month from the previous 12 months, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Prices used for the standardized measure above were as follows:

	2017	2016	2015
Natural gas *(per MMBtu)*	**$ 2.98**	$ 2.48	$ 2.59
Oil *(per Bbl)*	**$ 47.79**	$ 39.25	$ 46.79
NGLs *(per Bbl)*	**$ 14.41**	$ 6.74	$ 6.82

Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the year-end statutory rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved gas and oil properties after giving effect to permanent differences and tax credits.

Following is an analysis of changes in the standardized measure during 2017, 2016 and 2015:

(in millions)	**2017**	2016	2015
Standardized measure, beginning of year	**$ 1,665**	$ 2,417	$ 7,543
Sales and transfers of natural gas and oil produced, net of production costs	**(1,191)**	(574)	(1,082)
Net changes in prices and production costs	**1,963**	(415)	(8,075)
Extensions, discoveries, and other additions, net of future production and development costs	**1,715**	45	162
Acquisition of reserves in place	**–**	–	28
Sales of reserves in place	**–**	(10)	(244)
Revisions of previous quantity estimates	**1,721**	(140)	(1,385)
Net change in income taxes	**(222)**	–	1,915
Changes in estimated future development costs	**(6)**	71	2,007
Previously estimated development costs incurred during the year	**55**	114	875
Changes in production rates (timing) and other	**(304)**	(85)	(273)
Accretion of discount	**166**	242	946
Standardized measure, end of year	**$ 5,562**	$ 1,665	$ 2,417

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act. Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of December 31, 2017 at a reasonable assurance level.

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting is included on page 69 of this Annual Report.

PricewaterhouseCoopers LLP's report on Southwestern Energy's internal control over financial reporting is included in its Report of Independent Registered Public Accounting Firm on page 69 of this Annual Report.

ITEM 9B. OTHER INFORMATION

There was no information required to be disclosed in a current report on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2017, that was not reported on such form.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The definitive proxy statement to holders of the Company's common stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Stockholders to be held on or about May 22, 2018 (the "Proxy Statement"), is hereby incorporated by reference for the purpose of providing information about the Company's directors, and for discussion of its audit committee and its audit committee financial expert. Refer to the sections "Proposal No. 1: Election of Directors" and "Share Ownership of Management, Directors and Nominees" in the Proxy Statement for information concerning our directors. Refer to the section "Corporate Governance – Committees of the Board of Directors" in the 2018 Proxy Statement for discussion of its audit committee and its audit committee financial expert. Information concerning the Company's executive officers is presented in Part I of this Annual Report. The Company refers you to the section "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement for information relating to compliance with Section 16(a) of the Exchange Act.

Code of Business Ethics and Conduct for Directors and Employees

The Company has adopted a code of ethics that applies to its Chief Executive Officer, Chief Financial Officer and Controller as well as other officers and employees. We have posted a copy of our code of ethics on the "Corporate Governance" section of our website at www.swn.com, and it is available free of charge in print to any stockholder who requests it. Requests for copies should be addressed to the Secretary at 10000 Energy Drive, Spring, Texas 77389. Any amendments to, or waivers from, our code of ethics that apply to our executive officers and directors will be posted on the "Corporate Governance" section of our website.

ITEM 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 22, 2018, and is incorporated herein by reference.*

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 22, 2018, and is incorporated herein by reference.*

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 22, 2018, and is incorporated herein by reference.*

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2018 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 22, 2018, and is incorporated herein by reference.*

* Except for information or data specifically incorporated by reference under Items 10 through 14, all other information in our 2018 Proxy Statement is not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as part of this report.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) The consolidated financial statements of Southwestern Energy Company and its subsidiaries and the report of independent registered public accounting firm are included in Item 8 of this Annual Report.
  (2) The consolidated financial statement schedules have been omitted because they are not required under the related instructions, or are not applicable.
  (3) The exhibits listed on the accompanying Exhibit Index are filed as part of, or incorporated by reference into, this Annual Report.

ITEM 16. SUMMARY

None.

SIGNATURES

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

	SOUTHWESTERN ENERGY COMPANY
Dated: March 1, 2018	By: /s/ JENNIFER E. STEWART
	Jennifer E. Stewart
	Senior Vice President
	and Chief Financial Officer – Interim

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of March 1, 2018, on behalf of the Registrant below by the following officers and by a majority of the directors.

/s/ WILLIAM J. WAY William J. Way	Director, President and Chief Executive Officer (Principal executive officer)
/s/ JENNIFER E. STEWART Jennifer E. Stewart	Senior Vice President and Chief Financial Officer – Interim (Principal financial officer)
/s/ COLIN P. O'BEIRNE Colin P. O'Beirne	Vice President, Controller (Principal accounting officer)
/s/ JOHN D. GASS John D. Gass	Director
/s/ CATHERINE A. KEHR Catherine A. Kehr	Director
/s/ GREG D. KERLEY Greg D. Kerley	Director
/s/ GARY P. LUQUETTE Gary P. Luquette	Director
/s/ JON A. MARSHALL Jon A. Marshall	Director
/s/ ELLIOTT PEW Elliott Pew	Director
/s/ PATRICK M. PREVOST Patrick M. Prevost	Director
/s/ TERRY W. RATHERT Terry W. Rathert	Director
/s/ ALAN H. STEVENS Alan H. Stevens	Director

EXHIBIT INDEX

Exhibit Number	Description
2.1	Purchase Agreement dated as of October 14, 2014 between Southwestern Energy Production Company and Chesapeake Appalachia, L.L.C. (Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed on October 17, 2014)
2.2	Settlement Agreement, dated December 22, 2014, between Chesapeake Appalachia, L.L.C. and SWN Production Company, LLC (Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on December 23, 2014)
3.1	Amended and Restated Certificate of Incorporation of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed May 24, 2010)
3.2	Amended and Restated Bylaws of Southwestern Energy Company, as amended on April 25, 2017. (Incorporated by reference to Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017)
3.3	Certificate of Designations of 6.25% Series B Mandatory Convertible Preferred Stock (including form of stock certificate). (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on January 21, 2015)
3.4	Certificate of Designation, Preferences and Rights of Series A Junior Participating Preferred Stock, dated April 9, 2009. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on April 9, 2009)
4.1	Form of Common Stock Certificate. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.2	Policy on Confidential Voting of Southwestern Energy Company. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2006 Annual Meeting of Stockholders)
4.3	Indenture, dated as of December 1, 1995 between Southwestern Energy Company and The First National Bank of Chicago, as trustee. (Incorporated by reference to Exhibit 4 to Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (File No. 33-63895) filed on November 17, 1995)
4.4	First Supplemental Indenture between Southwestern Energy Company and J.P. Morgan Trust Company, N.A. (as successor to the First National Bank of Chicago) dated June 30, 2006. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.5	Second Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee (as successor to J.P. Morgan Trust Company, N.A.), dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K/A filed on May 8, 2008)
4.6	Indenture dated June 1, 1998 by and among NOARK Pipeline Finance, L.L.C. and The Bank of New York. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed May 4, 2006)
4.7	First Supplemental Indenture dated May 2, 2006 by and among Southwestern Energy Company, NOARK Pipeline Finance, L.L.C., and UMB Bank, N.A., as trustee (as successor to the Bank of New York). (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed May 4, 2006)
4.8	Second Supplemental Indenture between Southwestern Energy Company and UMB Bank, N.A., as trustee, dated June 30, 2006. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.9	Third Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and UMB Bank, N.A., as trustee, dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K/A filed on May 8, 2008)

4.10	Guaranty dated June 1, 1998 by Southwestern Energy Company in favor of The Bank of New York, as trustee, under the Indenture dated as of June 1, 1998 between NOARK Pipeline Finance L.L.C. and such trustee. (Incorporated by reference to Exhibit 4.6 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2005)
4.11	Indenture dated January 16, 2008 among Southwestern Energy Company, the Guarantors named therein and The Bank of New York Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed January 16, 2008)
4.12	Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee, dated as of March 5, 2012. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed March 6, 2012)
4.13	First Supplemental Indenture, dated as of November 29, 2017 between Southwestern Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on December 1, 2017)
4.14	Credit Agreement dated December 16, 2013 among Southwestern Energy Company, JPMorgan Chase Bank, NA, Bank of America, N.A., Wells Fargo N.A., The Royal Bank of Scotland PLC, Citibank, N.A. and the other lenders named therein, JPMorgan Chase Bank, NA, as administrative agent. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed December 17, 2013)
4.15	Form of certificate for the 6.25% Series B Mandatory Convertible Preferred Stock. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on January 21, 2015)
4.16	Deposit Agreement, dated as of January 21, 2015, between Southwestern Energy Company and Computershare Trust Company, N.A., as depositary, on behalf of all holders from time to time of the receipts issued thereunder (including form of Depositary Receipt). (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on January 21, 2015)
4.17	Form of Depositary Receipt for the Depositary Shares. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on January 21, 2015)
4.18	Indenture, dated as of January 23, 2015 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
4.19	Form of 3.300% Notes due 2018. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
4.20	Form of 4.050% Notes due 2020. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
4.21	Form of 4.95% Notes due 2025. (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
4.22	First Supplemental Indenture, dated as of January 23, 2015 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
4.23	Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.24	Form of 7.50% Notes due 2026. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.25	Form of 7.75% Notes due 2027. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.26	First Supplemental Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)

4.27	Second Supplemental Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.28	Third Supplemental Indenture, dated as of November 29, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on December 1, 2017)
10.1	Form of Second Amended and Restated Indemnity Agreement between Southwestern Energy Company and each Executive Officer and Director of the Registrant. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
10.2	Form of Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company, effective February 17, 1999. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.3	Form of Amendment to Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company prior to 2011. (Incorporated by reference to Exhibit 10.3 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008)
10.4	Form of Executive Severance Agreement between Southwestern Energy Company and Executive Officers Post 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant's Annual Report on Form 10-K (Commission File No.1-08426) for the year ended December 31, 2011)
10.5	Southwestern Energy Company Supplemental Retirement Plan as amended. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on February 19, 2008)
10.6	Southwestern Energy Company Non-Qualified Retirement Plan as amended. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on February 19, 2008)
10.7	Amendment One to the Southwestern Energy Company Non-Qualified Retirement Plan (Incorporated by reference to Exhibit 10.9 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009)
10.8	Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Annex A of the Registrant's Proxy Statement filed April 8, 2013)
10.9	First Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 20, 2016)
10.10	Second Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 30, 2017)
10.11	Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016)
10.12	Southwestern Energy Company 2013 Incentive Plan Guidelines for Annual Incentive Awards. (Incorporated by reference to Exhibit 10.03 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.13	Southwestern Energy Company 2013 Incentive Plan Form of Incentive Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.04 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.14	Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.05 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.15	Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement for Directors. (Incorporated by reference to Exhibit 10.06 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.16	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement. (Incorporated by reference to Exhibit 10.07 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)

10.17	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement for Directors, as amended on May 23, 2017. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017)
10.18	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement. (Incorporated by reference to Exhibit 10.09 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.19	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Directors. (Incorporated by reference to Exhibit 10.10 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.20	Form of Incentive Stock Option for awards granted on or after December 8, 2005. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.21	Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2005 and through December 8, 2011 (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.22	Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2011. (Incorporated by reference to Exhibit 10.20 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08426) for the year ended December 31, 2011)
10.23	Guaranty by and between Southwestern Energy Company and Texas Gas Transmission, LLC, dated as of October 27, 2008. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q (Commission File No. 1-08246) for the period ended September 30, 2008)
10.24	Guaranty by and between Southwestern Energy Company and Fayetteville Express Pipeline, LLC dated September 30, 2008 (Incorporated by reference to Exhibit 10.22 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009)
10.25	Retirement Letter Agreement dated February 24, 2012 between Southwestern Energy Company and Gene A. Hammons. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed February 27, 2012)
10.26	Retirement Agreement dated August 11, 2009 between Southwestern Energy Company and Harold M. Korell. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on August 14, 2009)
10.27	Retirement Agreement dated January 11, 2016 between Southwestern Energy Company and Steven L. Mueller. (Incorporated by reference to Exhibit 10.38 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2015)
10.28	Retirement Agreement dated May 19, 2016 between Southwestern Energy Company and Jeffrey B. Sherrick. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016)
10.29	Amendment to Awards Agreement dated May 19, 2016 between Southwestern Energy Company and Jeffrey B. Sherrick. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016)
10.30	Separation and Release Agreement dated August 23, 2017 between Southwestern Energy Company and Mark K. Boling. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
10.31	Amendment to Awards Agreement dated August 23, 2017 between Southwestern Energy Company and Mark K. Boling. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
10.32	Credit Agreement, dated June 27, 2016 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
10.33	Amendment No. 1 to Credit Agreement, dated as of June 27, 2016 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)

10.34	Amendment No. 1 to Credit Agreement, dated as of September 11, 2017 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as administrative agent, and each lender from time to time party thereto. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on September 11, 2017)
10.35	Amendment and Restatement Agreement, dated as of June 27, 2016 among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and the lenders party thereto, giving effect to the Amended and Restated Term Loan Credit Agreement. (Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
10.36	Amended and Restated Term Loan Credit Agreement, dated June 27, 2016 among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit A to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
21.1*	List of Subsidiaries
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of CEO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
95.1*	Mine Safety Disclosure
99.1*	Reserve Audit Report of Netherland, Sewell & Associates, Inc., dated February 2, 2018
101.INS*	Interactive Data File Instance Document
101.SCH*	Interactive Data File Schema Document
101.CAL*	Interactive Data File Calculation Linkbase Document
101.LAB*	Interactive Data File Label Linkbase Document
101.PRE*	Interactive Data File Presentation Linkbase Document
101.DEF*	Interactive Data File Definition Linkbase Document

*Filed herewith