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, 2015

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
Depositary Shares, each representing a 1/20th ownership interest in a share of 6.25% Series B Mandatory Convertible Preferred Stock	New York Stock Exchange

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was $8,694,538,969 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2015 of $22.73. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 23, 2016, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 389,664,470.

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 17, 2016 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, 2015

TABLE OF CONTENTS

		Page
PART I		
Item 1.	Business	3
	Glossary of Certain Industry Terms	23
Item 1A.	Risk Factors	28
Item 1B.	Unresolved Staff Comments	38
Item 2.	Properties	38
Item 3.	Legal Proceedings	41
Item 4.	Mine Safety Disclosures	41
PART II		
Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	41
	Stock Performance Graph	42
Item 6.	Selected Financial Data	43
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	45
	Overview	45
	Results of Operations	47
	Liquidity and Capital Resources	52
	Critical Accounting Policies and Estimates	56
	Cautionary Statement about Forward-Looking Statements	60
Item 7A.	Quantitative and Qualitative Disclosures about Market Risk	61
Item 8.	Financial Statements and Supplementary Data	63
	Index to Consolidated Financial Statements	63
Item 9.	Changes In and Disagreements With Accountants on Accounting and Financial Disclosure	107
Item 9A.	Controls and Procedures	107
Item 9B.	Other Information	107
PART III		
Item 10.	Directors, Executive Officers and Corporate Governance	108
Item 11.	Executive Compensation	109
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	109
Item 13.	Certain Relationships and Related Transactions, and Director Independence	109
Item 14.	Principal Accounting Fees and Services	109
PART IV		
Item 15.	Exhibits, Financial Statement Schedules	109
EXHIBIT INDEX		111

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. The public may 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. We file our reports 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.

ITEM 1. BUSINESS

Southwestern Energy Company (including its subsidiaries, collectively, “we”, “Southwestern” or the “Company”) is an independent natural gas and oil company with operations predominantly in the United States, 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. Southwestern’s common and preferred stock are listed and traded on the NYSE under the ticker symbols “SWN” and “SWNC”, respectively.

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, Arkansas; Tunkhannock, Pennsylvania; and Jane Lew, West Virginia.

Our Business Strategy

Our Company is guided by our formula, which represents the essence of our corporate philosophy and how we operate our business:

$$\frac{R^2}{A} \rightarrow V^{+}$$®

Our formula, which stands for “The Right People doing the Right Things, wisely investing the cash flow from our underlying Assets will create Value+,” also guides our business strategy. The key elements of our business strategy, along with how we are implementing them in the current low commodity price environment, are as follows:

- *Maintain a Strong Balance Sheet and Liquidity to Enhance Long-Term Shareholder Value.* We believe a strong balance sheet and liquidity position are important to long-term value creation and extremely valuable in challenging pricing environments, helping to preserve options and flexibility.
  - *What We Are Doing Now.* As commodity prices fell during 2015, we reduced our capital program by approximately $800 million from what we expected early in the year. We are also committed to investing within cash flow levels rather than increasing debt in this lower-price environment. Although we have opportunities that meet our investment threshold described below, we are currently not drilling new wells as we focus on decreasing our debt levels. If and when prices improve and sufficient cash flow is generated, we expect to increase our activity levels and pursue these opportunities. With respect to debt and maturities, early in 2015 we paid off $5.0 billion of bank debt with long-term notes and equity, and late in the year we increased our liquidity by $750 million by entering into a three-year term loan and utilized the proceeds to pay down our revolving credit facility. We continue to look at ways to reduce debt levels and extend maturities.

- *Exercise 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.
  - *What We Are Doing Now.* We continuously reassess our price expectations used in calculating expected PVI to align with market conditions. The current price environment reduces the number of wells and other projects that meet our PVI threshold, but even at current prices, we have projects that we expect would generate 1.3 PVI or above. As discussed above, the timing of those projects depends on availability of capital.

- *Maximizing Margins and Production Available for Sale.* We concentrate our operations in large, scalable projects, such as our large positions in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale. We believe this allows us the economies of scale that drives efficiency and learning opportunities. These efficiencies and learnings help improve future well results and enhance the economics of our portfolio. They also allow us to continuously identify ways to lower costs in each asset in which we operate. We routinely review costs in detail and analyze processes implemented, materials used and vendor relationships to enhance our economics and cost structure.

- *What We Are Doing Now.* Cost control has been a differentiator for us in the past, and we believe our focus on costs gives us a competitive advantage as we move into the future. We have successfully renegotiated contracts, improved well results and implemented continuous process improvements in each of our operating areas, resulting in these differentiating cost savings.

Our predominant operations, which we refer to as Exploration and Production ("E&P"), are focused on the finding and development of natural gas and oil 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 Services. We conduct substantially all of our business through subsidiaries.

Exploration and Production - Our primary business is the exploration for and production of natural gas and oil, with our current operations principally focused within the United States on development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. Our operations in northeast Pennsylvania are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale (herein referred to as "Northeast Appalachia"), our operations in West Virginia are also focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs (herein referred to as "Southwest Appalachia") 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 also actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which we refer to as "New Ventures." We have exploration and production activities ongoing in Colorado and Louisiana along with other areas in which we are currently exploring for new development opportunities. We also have drilling rigs located in Pennsylvania, West Virginia and Arkansas and provide oilfield products and services, principally serving our exploration and production operations.

Midstream Services – 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 the natural gas, oil and NGLs produced in our E&P operations.

Historically, the vast majority of our operating income and earnings before interest, taxes, depreciation, depletion and amortization and any non-cash impairment of natural gas and oil properties, (gain) loss on derivatives, excluding derivatives, settled, gain on sale of assets and certain one-time charges ("Adjusted EBITDA"), have been derived from our E&P business. However, in 2015, depressed commodity prices significantly decreased our E&P results. In 2015, our E&P business had an operating loss of $154 million, excluding non-cash impairments of natural gas and oil properties, and constituted 75% of our Adjusted EBITDA, had operating income of $1,013 million in 2014 and constituted 82% of our Adjusted EBITDA and had an operating income of $879 million in 2013 and constituted 81% of our Adjusted EBITDA. The remainder of our consolidated operating income and Adjusted EBITDA in each of these years was primarily generated from Midstream Services. Adjusted EBITDA is a non-GAAP measure. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations — Reconciliation of Non-GAAP Measures" in Item 7 of Part II of this Annual Report for a table that reconciles Adjusted EBITDA to net income (loss).

Recent Developments

CEO Succession. In January 2016, Steve Mueller, Chief Executive Officer since 2009, announced his retirement. He will remain on the Board of Directors as Non-Executive Chairman through the annual shareholder meeting in May 2016. Bill Way, previously the President and Chief Operating Officer of the company, was named Chief Executive Officer to replace Mr. Mueller. Mr. Way retained his title of President and was appointed to the Board of Directors.

Workforce Reduction. In January 2016, as a result of lower anticipated drilling activity we announced a 40% workforce reduction of approximately 1,100 employees, which included a majority of employees in our oilfield services businesses. This reduction should be substantially complete by the end of the first quarter of 2016.

Exploration and Production

Overview

Operations in our E&P segment are primarily in the Appalachian Basin and Fayetteville Shale assets. We also have conducted additional exploration and production activities in other basins targeting various formations as part of our New Ventures projects.

Our E&P segment recorded an operating loss of $7,104 million in 2015, operating income of $1,013 million in 2014, and operating income of $879 million in 2013. The operating loss in 2015 was primarily a result of $7.0 billion, or $4.3 billion net of taxes, non-cash impairments of natural gas and oil properties due to the fall in commodity prices. Operating income for 2014 increased $134 million compared to 2013 as a result of an increase in revenue of $403 million from higher production volumes, an increase in revenue of $55 million from increased realized prices, offset by an increase in operating costs and expenses of $324 million associated with the expansion of our operations and higher activity levels in Northeast Appalachia and the Fayetteville Shale. In May 2015, we divested of our East Texas and Arkoma properties, previously referred to as the Ark-La-Tex division.

Adjusted EBITDA from our E&P segment was $1.1 billion in 2015, compared to $1.9 billion in 2014 and $1.6 billion in 2013. Our Adjusted EBITDA decreased in 2015 as lower realized natural gas prices and increased total operating costs and expenses due to increased activity levels more than offset the revenue impacts of higher production volumes. Our Adjusted EBITDA increased in 2014 as higher realized natural gas prices and production volumes more than offset increased total operating costs and expenses due to increased activity levels. Adjusted EBITDA is a non-GAAP measure. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Reconciliation of Non-GAAP Measures" in Item 7 of Part II of this Annual Report for a table that reconciles Adjusted EBITDA to net income (loss).

Oilfield Services Vertical Integration

We seek to provide oilfield services that are strategic and economically beneficial for our E&P operations when our E&P activity levels support these activities. This vertical integration lowers our net well costs, allows us to operate safely and efficiently and mitigates certain operational environmental risks. Among others, these services include drilling, hydraulic fracturing and the mining of proppant used for our well completions. In 2016 through February 23, these operations have largely been inactive and we expect lower activity in these areas in 2016 due to reduced drilling activity resulting from lower commodity prices.

<u>Drilling Services</u>

We have conducted drilling operations for a majority of our operated wells. As of December 31, 2015, we had 13 re-entry rigs and 2 spudder rigs which were located in Pennsylvania, West Virginia, and Arkansas. In 2015, we provided drilling services for 82, 41 and 230 wells that we operate in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale, respectively, and were able to reduce our drilling costs on average by 1%, 2% and 1% per well for the wells we drilled in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale, respectively.

<u>Hydraulic Fracturing</u>

We provide pressure pumping services for a portion of our operated wells. As of December 31, 2015, we operated 2 leased pressure pumping spreads with a total capacity of approximately 72,000 horsepower to conduct a variety of completion services designed to stimulate natural gas production. In 2015, we provided pressure pumping services for 192 wells that we operated in the Fayetteville Shale and were able to reduce our well completion costs on average by 6% per well for the wells we completed.

<u>Sand Mine</u>

Since 2009, we have owned and operated a sand mine to provide a reliable supply of proppant primarily used for the completion of our wells that we operate in the Fayetteville Shale. As of December 31, 2015, our sand mine is comprised of 570 acres and produces 30/70 and 100 mesh sized sand. In 2015, we provided sand for the completion of 261 wells operated by us in the Fayetteville Shale and were able to reduce our well completion costs on average by 11% per well for the wells for which we provided sand.

Our Proved Reserves

Our estimated proved natural gas and oil reserves were 6,215 Bcfe at year-end 2015, compared to 10,747 Bcfe at year-end 2014 and 6,976 Bcfe at year-end 2013. The significant decrease in our reserves in 2015 was primarily due to downward price revisions in our proved undeveloped reserves associated with decreased commodity prices, partially offset by upward performance revisions in Northeast Appalachia and Southwest Appalachia and our successful development programs in the Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale. The significant increase in our reserves in 2014 was primarily due to the acquisition of approximately 413,000 net acres in Southwest Appalachia, our successful development drilling programs in Northeast Appalachia and the Fayetteville Shale and upward performance revisions in Northeast Appalachia. 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 and oil reserve quantities, are highly dependent upon the natural gas price used in our reserve and after-tax PV-10 calculations. In order to value our estimated proved natural gas, NGL and oil reserves as of December 31, 2015, we utilized average prices from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.59 per MMBtu for natural gas, West Texas Intermediate oil of $46.79 per barrel for oil and $6.82 per barrel for NGLs compared to $4.35 per MMBtu for natural gas, $91.48 per barrel for oil and $23.79 per barrel for NGLs at December 31, 2014 and $3.67 per MMBtu for natural gas, $93.42 per barrel for oil and $43.45 per barrel for NGLs at December 31, 2013.

Our after-tax PV-10 was $2.4 billion at year-end 2015, $7.5 billion at year-end 2014, and $3.7 billion at year-end 2013. The decrease in our after-tax PV-10 value in 2015 compared to 2014 was primarily due to lower average natural gas, oil and NGL prices. The increase in our after-tax PV-10 value in 2014 over 2013 was primarily due to an increase in our reserves and higher average natural gas prices. The difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2015 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 2015 after-tax PV-10 computation does not have future income taxes because our tax basis in the associated oil and gas properties exceeded expected pre-tax cash inflows. Our year-end 2015 estimated proved reserves had a present value of estimated future net cash flows before income tax, or pre-tax PV-10, of $2.4 billion, compared to $9.5 billion at year-end 2014 and $5.1 billion at year-end 2013.

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. While pre-tax PV-10 is based on prices, costs and discount factors that are comparable from company to company, 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 Note 4 in the consolidated financial statements 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.

At year-end 2015, 95% of our estimated proved reserves were natural gas and 93% of total estimated proved reserves were classified as proved developed, compared to 91% and 55%, respectively, in 2014 and 100% and 61%, respectively in 2013. We operate, or if operations have not commenced, plan to operate, approximately 98% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index approximated 6.4 years at year-end 2015. In 2015, natural gas sales accounted for 93% of total operating revenues, compared to nearly 100% in 2014 and 2013.

The following table provides an overall and categorical summary of our natural gas, oil and NGL reserves, as of fiscal year-end 2015 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2015 and sets forth 2015 annual information related to production and capital investments for each of our operating areas:

2015 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	Appalachia				
	Northeast	**Southwest**	**Fayetteville Shale**	**Other (1)**	**Total**
Estimated Proved Reserves:					
Natural Gas (Bcf):					
Developed (Bcf)	2,005	311	3,156	2	**5,474**
Undeveloped (Bcf)	314	4	125	–	**443**
	2,319	315	3,281	2	**5,917**
Crude Oil (MMBbls):					
Developed (MMBbls)	–	8.5	–	0.3	**8.8**
Undeveloped (MMBbls)	–	–	–	–	**–**
	–	8.5	–	0.3	**8.8**
Natural Gas Liquids (MMBbls):					
Developed (MMBbls)	–	40.9	–	–	**40.9**
Undeveloped (MMBbls)	–	–	–	–	**–**
	–	40.9	–	–	**40.9**
Total Proved Reserves (Bcfe)(2):					
Developed (Bcfe)	2,005	607	3,156	4	**5,772**
Undeveloped (Bcfe)	314	4	125	–	**443**
	2,319	611	3,281	4	**6,215**
Percent of Total	37%	10%	53%	0%	**100%**
Percent Proved Developed	86%	99%	96%	100%	**93%**
Percent Proved Undeveloped	14%	1%	4%	0%	**7%**
Production (Bcfe)	360	143	465	8	**976**
Capital Investments (millions)(3)	$ 710	$ 857	$ 565	$ 105	**$ 2,237**
Total Gross Producing Wells(4)	774	1,085	4,268	20	**6,147**
Total Net Producing Wells(4)	407	859	2,971	17	**4,254**
Total Net Acreage	270,335 (5)	425,098 (6)	957,641 (7)	3,673,853 (8)	**5,326,927**
Net Undeveloped Acreage	168,753 (5)	193,582 (6)	288,569 (7)	3,661,375 (8)	**4,312,279**
PV-10:					
Pre-Tax (millions)(9)	$ 707	$ 115	$ 1,604	$ (9)	**$ 2,417**
PV of Taxes (millions)(9)	–	–	–	–	**–**
After-Tax (millions)(9)	$ 707	$ 115	$ 1,604	$ (9)	**$ 2,417**
Percent of Total	29%	5%	66%	0%	**100%**
Percent Operated(10)	98%	95%	99%	100%	**98%**

(1) Other includes New Ventures and the production from our Ark-La-Tex properties divested in May 2015.

(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) Our Total and Fayetteville Shale capital investments exclude $21 million related to our drilling rig related equipment, sand facility and other equipment.

(4) Represents all producing wells, including wells in which we only have an overriding royalty interest, as of December 31, 2015.

(5) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 30,172 net acres in 2016, 57,724 net acres in 2017 and 12,891 net acres in 2018.

(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended leasehold expiring over the next three years will be 36,934 net acres in 2016, 42,034 net acres in 2017 and 12,604 net acres in 2018. Of this acreage, 16,160 net acres in 2016, 15,262 net acres in 2017 and 1,990 net acres in 2018 can be extended for an average of an additional 4.8 years.

(7) The Fayetteville Shale acreage includes 31,413 net undeveloped acres and 170,743 net developed acres in the Arkoma Basin that have previously been reported as a component of our conventional Arkoma acreage. Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 164 net acres in 2016, 453 net acres in 2017 and 31 net acres in 2018 (excluding 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management).

(8) Assuming successful wells are not drilled to develop the acreage and leases are not extended, our leasehold expiring over the next three years, excluding New Brunswick, Canada, the Lower Smackover Brown Dense area and the Sand Wash Basin, will be 255,527 net acres in 2016, 217,927 net acres in 2017 and 23,086 net acres in 2018. With regard to our acreage in New Brunswick, Canada, exploration licenses were extended through 2021. With regard to our acreage in the Lower Smackover Brown Dense, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 58,849 net acres in 2016, 68,790 net acres in 2017 and 67,528 net acres in 2018. With regard to our acreage in the Sand Wash Basin, assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 85,767 net acres in 2016, 35,883 net acres in 2017, and 55,918 net acres in 2018.

(9) 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.

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

We refer you to Note 4 to our consolidated financial statements 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 2013, 2014 and 2015.

CHANGES IN PROVED UNDEVELOPED RESERVES (BCFE)

	Appalachia				
	Northeast	**Southwest**	**Fayetteville Shale**	**Other (1)**	**Total**
December 31, 2012	**442**	**–**	**364**	**15**	**821**
Extensions, discoveries and other additions (2)	810	–	1,530	–	**2,340**
Total revision attributable to performance and production	(33)	–	(115)	(9)	**(157)**
Price revisions	26	–	18	1	**45**
Developed	(170)	–	(142)	–	**(312)**
Disposition of reserves in place	–	–	–	–	–
Acquisition of reserves in place	–	–	–	–	–
December 31, 2013	**1,075**	**–**	**1,655**	**7**	**2,737**
Extensions, discoveries and other additions (3)	589	–	573	–	**1,162**
Total revision attributable to performance and production (4)	307	–	(130)	(6)	**171**
Price revisions	11	–	24	–	**35**
Developed	(384)	–	(406)	–	**(790)**
Disposition of reserves in place	–	–	–	–	–
Acquisition of reserves in place (5)	–	1,481	–	–	**1,481**
December 31, 2014	**1,598**	**1,481**	**1,716**	**1**	**4,796**
Extensions, discoveries and other additions	138	4	34	–	**176**
Total revision attributable to performance and production	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**

(1) Other includes New Ventures and Ark-La-Tex properties divested in May 2015.

(2) The 2013 proved undeveloped reserve additions are primarily associated with the increase in gas prices.

(3) Primarily associated with the undeveloped locations that were added throughout the year in 2014 due to our successful drilling program.

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

(5) Our acquisition of reserves in place is attributable to the purchase of undeveloped locations in West Virginia and southwest Pennsylvania.

As of December 31, 2015, we had 443 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 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. As of December 31, 2014, we had 4,796 Bcfe of proved undeveloped reserves. During 2014, we invested $767 million in connection with converting 790 Bcfe, or 29%, of our proved undeveloped reserves as of December 31, 2013 into proved developed reserves and added 2,643 Bcfe of proved undeveloped reserve additions in the Appalachian Basin and the Fayetteville Shale. Our December 31, 2015 proved reserves include 217 Bcfe of proved undeveloped reserves from 75 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 $34 million when discounted at 10%. We have made a final investment decision and are committed to developing these reserves within the next five years.

We expect that the development costs for our proved undeveloped reserves of 443 Bcfe as of December 31, 2015 will require us to invest an additional $235 million 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 decreased 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 revenues, profitability, liquidity and growth and the value of our assets,” “Significant capital expenditures are required to replace our reserves and conduct our business,” and “Lower commodity prices may impair our ability to service our existing debt or refinance it when it becomes due” 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

The reserve replacement ratio measures the ability of an exploration and production company to add new reserves to replace the reserves that are being depleted by its current production volumes. The reserve replacement ratio, which we discuss below, is an important analytical measure used by investors and peers in the E&P industry to evaluate performance results and long-term prospects. There are limitations as to the usefulness of this measure, as it does not reflect the type of reserves or the cost of adding the reserves or indicate the potential value of the reserve additions.

In 2015, our reserve replacement ratio was negatively affected by net downward revisions of 4,083 Bcfe primarily as a result of the depressed commodity price environment. Excluding reserve revisions, we replaced 72% of our production volumes with 592 Bcfe of proved reserve additions and 114 Bcfe of proved reserve additions as a result of acquisitions. Of the reserve additions, 416 Bcfe were proved developed and 176 Bcfe were proved undeveloped. In 2015, downward reserve revisions resulting from lower natural gas, oil and NGL prices totaled 2,315 Bcf, 1,875 Bcfe, 1,496 Bcf and 32 Bcfe in our Northeast Appalachia, Southwest Appalachia, Fayetteville Shale and other divisions, respectively. We also had upward performance revisions in 2015 of 1,383 Bcf, 209 Bcfe, 10 Bcf and 33 Bcfe in our Northeast Appalachia, Southwest Appalachia, Fayetteville Shale and other divisions, respectively. Additionally, our reserves decreased by 179 Bcfe as a result of our sale of natural gas and oil leases and wells in 2015.

In 2014, we replaced 591% of our production volumes with 1,693 Bcfe of proved reserve additions, net upward revisions of 543 Bcfe, and 2,304 Bcfe of proved reserve additions as a result of acquisitions. Of the reserve additions, 531 Bcfe were proved developed and 1,162 Bcfe were proved undeveloped. In 2014, upward reserve revisions resulting from higher gas prices totaled 38 Bcf, 10 Bcf and 6 Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. We also had performance revisions in 2014 of (126) Bcf, 636 Bcf and (21) Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. Additionally, our reserves increased by 2,304 Bcfe in 2014 as a result of acquisitions primarily associated with acreage in Southwest Appalachia. Our reserve replacement ratio, excluding reserve revisions, was 520% in 2014.

In 2013, we replaced 550% of our production volumes with 3,285 Bcfe of proved reserve additions, net upward revisions of 326 Bcfe, and 4 Bcfe of proved reserve additions as a result of acquisitions. Of the reserve additions, 945 Bcfe were proved developed and 2,340 Bcfe were proved undeveloped. In 2013, upward reserve revisions resulting from higher gas prices totaled 191 Bcf, 35 Bcf and 21 Bcf in our Fayetteville Shale, Northeast Appalachia and Ark-La-Tex divisions, respectively. We also had upward performance revisions in 2013 of 16 Bcf, 62 Bcf and 1 Bcf in our Fayetteville Shale, Northeast Appalachia and New Ventures divisions, respectively. Additionally, our reserves increased by 4 Bcf in 2013 as a result of our acquisition of natural gas leases and wells. Our reserve replacement ratio, excluding reserve revisions, was 501% in 2013.

For the period ended December 31, 2015, our three-year average reserve replacement ratio, including revisions and acquisitions, was 199%. Excluding reserve revisions and acquisitions, our three-year average reserve replacement ratio was 232%.

Since 2005, the substantial majority of our reserve additions have been generated from our Fayetteville Shale division. However, over the past several years, Northeast Appalachia has also contributed to an increasing amount of our reserve additions as a result of increased development activity, totaling 419 Bcf, 836 Bcf and 1,200 Bcf in 2015, 2014 and 2013, respectively. Additionally, we added 123 Bcfe of reserves in 2015 as a result of our drilling program in Southwest Appalachia, which was acquired in December 2014. We expect our drilling programs in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale 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

We began leasing acreage in northeast Pennsylvania in 2007 in an effort to participate in the emerging Marcellus Shale. As of December 31, 2015, we had approximately 270,335 net acres in Northeast Appalachia under which we believe the Marcellus Shale is present (168,753 net undeveloped acres and 101,582 net developed acres held by production), compared to approximately 266,073 net acres at year-end 2014 and 292,446 net acres at year-end 2013. Our undeveloped acreage position as of December 31, 2015 had an average royalty interest of 15% and was obtained at an average cost of approximately $990 per acre.

As of December, 31, 2015, we had spud or acquired 553 operated wells, 424 of which were on production and 542 of which are horizontal wells. In 2015, we invested approximately $710 million in Northeast Appalachia and spud 89 operated horizontal wells and acquired 86 horizontal and 2 vertical wells. Our reserves in Northeast Appalachia decreased by 873 Bcf in 2015, which included reserve additions of 340 Bcf, 1,383 Bcf of net upward revisions due to well performance, net downward price revisions of 2,315 Bcf and acquisitions of 79 Bcf, offset by production of 360 Bcf. Of the 89 horizontal wells spud during 2015, 79 wells are located in Susquehanna County, 4 wells are located in Bradford County, 4 wells are located in Tioga County and the remaining 2 wells are located in Wyoming County. We also acquired 86 horizontal wells in 2015, nearly all of which were located in Susquehanna County. In 2015, our operated horizontal wells had an average completed well cost of $5.4 million per well, average horizontal lateral length of 5,403 feet and an average of 11 fracture stimulation stages. This compares to an average completed operated well cost of $6.1 million per well, average horizontal lateral length of 4,752 feet and an average of 15 fracture stimulation stages in 2014. In 2013, our average completed operated well cost was $7.0 million per well with an average horizontal lateral length of 4,982 feet and an average of 18 fracture stimulation stages. Included in our total capital investments in Northeast Appalachia during 2015 was approximately $472 million for drilling and completions, $172 million for acquisition of properties, and $66 million in facilities, capitalized costs and other expenses. In 2014, we invested approximately $695 million in Northeast Appalachia, spud 99 operated wells, and acquired 5 horizontal and 2 vertical wells, resulting in reserve additions and revisions of 1,483 Bcf. In 2013, we invested approximately $872 million in Northeast Appalachia and spud 108 operated wells, resulting in net reserve additions and revisions of 1,297 Bcf.

Approximately 2,319 Bcf of our total proved net reserves at year-end 2015 were attributable to Northeast Appalachia. We had a total of 423 horizontal and one vertical well that we operated and that were on production as of December 31, 2015, resulting in net production from this area of 360 Bcf in 2015, compared to 254 Bcf in 2014 and 151 Bcf in 2013. Our 2015 year-end reserves in Northeast Appalachia include a total of 826 locations, of which 767 were proved developed producing, 23 were proved developed non-producing and 36 were proved undeveloped. At year-end 2014, we had approximately 3,192 Bcf in proved reserves in Northeast Appalachia from a total of 737 locations, of which 524 were proved developed producing, 13 were proved developed non-producing and 200 were proved undeveloped. At year-end 2013, we had approximately 1,963 Bcf of proved reserves in Northeast Appalachia from a total of 522 locations, of which 333 were proved developed producing, and 189 were proved undeveloped. The average gross proved reserves for the undeveloped wells included in our year-end reserves for 2015 was approximately 10.4 Bcf per well, compared to 9.6 Bcf per well at year-end 2014 and 6.9 Bcf per well in 2013.

Our ability to bring our Northeast 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 Services" 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

In late 2014 and early 2015, we closed two transactions to acquire natural gas and oil assets in West Virginia and southwest Pennsylvania for approximately $5.4 billion. This acreage has at least three drilling objectives, namely the Marcellus, Utica and Upper Devonian Shales. As of December 31, 2015, we had approximately 425,098 net acres in Southwest Appalachia (193,582 net undeveloped acres and 231,516 net developed acres held by production) compared to approximately 413,376 net acres at year-end 2014. Our undeveloped acreage position as of December 31, 2015 had an average royalty interest of 16%.

In 2015, we invested approximately $857 million in Southwest Appalachia, which included approximately $248 million to spud 48 wells. Net production from Southwest Appalachia was 143 Bcfe in 2015. Included in our total capital investments in Southwest Appalachia during 2015 was approximately $409 million for acquisition of properties and $200 million in capitalized costs and other expenses. Approximately 611 Bcfe of our total proved net reserves at year-end 2015 were in Southwest Appalachia and substantially all attributable to the Marcellus Shale. Our reserves in Southwest Appalachia decreased by 1,686 Bcfe in 2015, which included reserve additions of 88 Bcfe, 209 Bcfe of net upward revisions due to well performance, net downward price revisions of 1,875 Bcfe, and acquisitions of 35 Bcfe, offset by production of 143 Bcfe. We had a total of 318 horizontal and 676 vertical wells that we operated and that were on production as of December 31, 2015. Additionally, there were 43 horizontal wells in progress at the end of 2015, of which 21 were waiting on pipeline or production facilities. Our 2015 year-end reserves in Southwest Appalachia include a total of 1,429 locations, of which 1,028 were proved developed producing, 400 were proved developed non-producing and 1 was proved undeveloped. At December 31, 2014, approximately 2,297 Bcfe of total proved net reserves were attributable to Southwest Appalachia from a total of 1,502 locations, of which 1,034 were proved developed producing, 124 were proved developed non-producing and 344 were proved undeveloped.

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 Services" 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 is a Mississippian-age unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, ranging in thickness from 50 to 550 feet and ranging in depth from 1,500 to 6,500 feet. As of December 31, 2015, we held leases for approximately 957,641 net acres in the play area (257,156 net undeveloped acres, 498,329 net developed acres held by Fayetteville Shale production, 170,743 net developed acres held by conventional production in the Arkoma Basin, and 31,413 net undeveloped acres in the Arkoma Basin), compared to approximately 888,161 net acres at year-end 2014 and 905,684 net acres at year-end 2013. Certain acreage previously reported as a component of our conventional Arkoma Basin has been included in the unconventional net acreage for the Fayetteville Shale at December 31, 2015, reflecting our current drilling focus.

Approximately 3,281 Bcf of our reserves at year-end 2015 were attributable to our Fayetteville Shale properties, compared to approximately 5,069 Bcf at year-end 2014 and 4,795 Bcf at year-end 2013. Our reserves in the Fayetteville Shale decreased by 1,788 Bcf in 2015, which included reserve additions of 163 Bcf, net downward price revisions of 1,496 Bcf, 10 Bcf of net upward revisions due to well performance, offset by production of 465 Bcf. Our net production from the Fayetteville Shale was 465 Bcf in 2015, compared to 494 Bcf in 2014 and 486 Bcf in 2013.

At year-end 2015, after excluding our acreage in the conventional Arkoma Basin and the federal acreage we hold in the Ozark Highlands Unit, approximately 87% of our 597,254 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. Our acreage position was obtained at an average cost of approximately $335 per acre and has an average royalty interest of 15%. We 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.

Following the commencement of two court actions, now 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 has discontinued approval of operational permits in the forest, including permits to drill, pending resolution of the litigation. The Ozark Highlands Unit lies entirely within the Ozark National Forest. Although we are not a party to the litigation and the plaintiffs' complaints do not seek invalidation of the leases, we currently are unable to obtain permits to drill on the 158,231 acres we have leased in the unit and the national forest.

As of December 31, 2015, we had spud a total of 4,737 wells in the Fayetteville Shale since our commencement of activities there in 2004, of which 4,157 were operated by us and 580 were outside-operated wells. Of these wells, 155 were spud in 2015, 468 in 2014 and 527 in 2013. All of the wells spud in 2015 were designated as horizontal wells. At year-end 2015, 4,003 wells operated by the Company had been drilled and completed overall, including 3,912 horizontal wells.

In 2015, the horizontal wells we drilled as operator had an average completed well cost of $2.8 million per well, average horizontal lateral length of 5,729 feet, and an average time to drill to total depth of 7.3 days from re-entry to re-entry. This compares to an average completed operated well cost of $2.6 million per well, average horizontal lateral length of 5,440 feet and average time to drill to total depth of 6.8 days from re-entry to re-entry during 2014. In 2013, our average completed operated well cost was $2.4 million per well with an average horizontal lateral length of 5,356 feet and average time to drill to total depth of 6.2 days from re-entry to re-entry. The operated wells we placed on production during 2015 averaged initial production rates of 4,280 Mcf per day, compared to average initial production rates of 4,430 Mcf per day in 2014 and 4,041 Mcf per day in 2013. During 2015, we placed 74 operated wells on production with initial production rates that exceeded 5.0 MMcf per day, compared to 145 wells in 2014 and 93 wells in 2013.

Our total proved net reserves in the Fayetteville Shale at year-end 2015 were from a total of 4,560 locations, of which 4,268 were proved developed producing, 231 were proved developed non-producing and 61 were proved undeveloped. Of the 4,560 locations, 4,493 were horizontal. The average gross proved reserves for the undeveloped wells included at year-end 2015 was approximately 3.0 Bcf per well, compared to 2.3 Bcf per well at year-end 2014, and 2.5 Bcf per well at year-end 2013. The increase in average gross proved reserves for our undeveloped wells in 2015 was primarily due to the estimated ultimate recoveries of those locations which remained economic at the average prices utilized during 2015. The decrease in average gross proved reserves for our undeveloped wells in 2014 was primarily due to the addition of proven undeveloped locations in areas of the field with lower estimated ultimate recoveries. Total proved net natural gas reserves in the Fayetteville Shale in 2014 were approximately 5,069 Bcf from a total of 5,445 locations, of which 4,045 were proved developed producing, 187 were proved developed non-producing and 1,213 were proved undeveloped. Total proved net natural gas reserves in the Fayetteville Shale in 2013 totaled approximately 4,795 Bcf from a total of 4,631 locations, of which 3,511 were proved developed producing, 59 were proved developed non-producing and 1,061 were proved undeveloped.

In 2015, we invested approximately $565 million in the Fayetteville Shale, which included approximately $481 million to spud 155 wells, all of which we operate. Included in our total capital investments in the Fayetteville Shale during 2015 were $80 million in capitalized costs and other expenses and $4 million for acquisition of properties. In 2014, we invested approximately $944 million in the Fayetteville Shale, which included $838 million to spud 468 wells, 464 of which we operate, $99 million in capitalized costs and other expenses and $7 million for acquisition of properties. In 2013, we invested approximately $907 million in the Fayetteville Shale, which included $804 million to spud 527 wells, 504 of which we operate, $97 million in capitalized costs and other expenses and $6 million for acquisition of properties. As of December 31, 2015, we had acquired approximately 1,324 square miles of 3-D seismic data, which provides us with seismic data on approximately 65% of our net acreage position in the Fayetteville Shale.

<u>New Ventures</u>

We also seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which we refer to as “New Ventures.” We have been focusing on both natural gas and oil unconventional plays, and the technological methods best suited to developing these plays, such as horizontal drilling and fracture stimulation techniques. New Ventures prospects are evaluated based on multi-well potential and land availability as well as other criteria and may be located both inside and outside of the United States. As of December 31, 2015, we held 3,661,375 net undeveloped acres in connection with our New Ventures prospects, of which 2,518,518 net acres were located in New Brunswick, Canada. This compares to 4,170,687 net undeveloped acres held at year-end 2014 and 3,972,732 net undeveloped acres held at year-end 2013.

Activity on our New Ventures assets was limited in 2015 as a result of the low commodity price environment. We are currently in the process of marketing these assets and anticipate activity to remain limited in 2016 as we focus on more proven development plays. Although we believe that our New Ventures projects have significant exploration and exploitation potential, there can be no assurance that any prospects will result in viable projects or that we will not abandon our initial investments.

Sand Wash Basin. In 2014, we acquired acreage in northwest Colorado targeting crude oil, NGLs and natural gas contained in the Sand Wash Basin, with the target zone ranging in vertical depth from 5,500 to 11,500 feet. Our leases currently have an approximate 81% average net revenue interest. As of December 31, 2015, we held approximately 251,478 net acres in the area, obtained at an average cost of $570 per acre.

Brown Dense. In July 2011, we announced that we would begin testing a new unconventional liquids rich play targeting the Brown Dense formation, an unconventional reservoir that ranges in vertical depths from 8,000 to 11,000 feet and appears to be laterally extensive over a large area ranging in thickness from 300 to 550 feet. As of December 31, 2015, we held approximately 201,091 net acres in the area, obtained at an average cost of $1,313 per acre. Our leases currently have an approximate 80% average net revenue interest. As of December 31, 2015, we had drilled 14 operated wells in the area, 6 of which were currently producing. In 2015, we processed and analyzed 3-D seismic data and believe that we have a better understanding of factors contributing to the quality of the wells drilled to date.

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 2,518,518 net acres in the province in order to test new hydrocarbon basins. In 2015, the provincial government in New Brunswick announced a moratorium on hydraulic fracturing until a list of conditions is met. The list of conditions that the provincial government has announced is somewhat subjective, and although the provincial government has stated that it expects to make a decision on the moratorium by the end of 2016, we cannot predict whether or when it may be lifted. Unless and until the moratorium is lifted, we will not be able to continue with our program in New Brunswick. In response to this moratorium, the Company requested and was granted an extension of its licenses. With these extensions, our licenses are scheduled to expire in March 2021.

Acquisitions and Divestitures

In May 2015, the Company 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, the Company sold its 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.

In March 2014 and July 2014, we acquired approximately 380,000 net acres in northwest Colorado principally in the Sand Wash Basin for approximately $215 million.

In April 2013, we acquired approximately 162,000 net acres in Northeast Appalachia for approximately $82 million. The acquired acreage is near our existing acreage in Northeast Appalachia.

Capital Investments

During 2015, we invested a total of approximately $2.3 billion in our E&P business. In 2015, we placed 430 wells to sales and had 203 wells in progress. Of the 203 wells in progress at year-end, 83, 43 and 77 were located in our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale operating areas, respectively, and 41 of these wells are waiting on pipeline or production facilities. Of the approximately $2.3 billion invested in our E&P business in 2015, approximately $710 million was invested in Northeast Appalachia, $857 million in Southwest Appalachia, $565 million in the Fayetteville Shale, and $102 million in New Ventures projects.

Of the $2.3 billion invested in 2015, approximately $1.2 billion was invested in exploratory and development drilling and workovers, $607 million for acquisition of properties, $390 million in capitalized interest and other expenses and $6 million for seismic expenditures. Additionally, we invested approximately $21 million in our drilling rigs and related equipment, sand facility and other equipment, and $8 million in water facilities. In 2014, we invested approximately $7.3 billion in our primary E&P business activities and participated in drilling 576 wells. Of the $7.3 billion invested in 2014, approximately $5.3 billion was invested for acquisition of properties, $1.5 billion in exploratory and development drilling and workovers, $247 million in capitalized interest and other expenses and $56 million for seismic expenditures. Additionally, we invested approximately $105 million in our drilling rigs and related equipment, sand facility and other equipment, and $5 million in water facilities. In 2013, we invested approximately $2.1 billion in our primary E&P business activities and participated in drilling 653 wells. Of the $2.1 billion invested in 2013, approximately $1.5 billion was invested in exploratory and development drilling and workovers, $224 million in capitalized interest and other expenses, $159 million for acquisition of properties, and $28 million for seismic expenditures. Additionally, we invested approximately $76 million in our drilling rigs and related equipment, sand facility and other equipment.

Based on current commodity prices, our capital program for 2016 will be flexible and aligned with expected cash flow. This will involve little, if any, drilling at current prices unless we realize additional cash. 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 2016.

Sales, Delivery Commitments and Customers

Sales. Our daily natural gas equivalent production averaged 2,675 MMcfe in 2015, compared to 2,105 MMcfe in 2014 and 1,800 MMcfe in 2013. Total natural gas equivalent production was 976 Bcfe in 2015, up from 768 Bcfe in 2014 and 657 Bcfe in 2013. Our natural gas production was 899 Bcf in 2015, compared to 766 Bcf in 2014 and 656 Bcf in 2013. The increase in production in 2015 resulted primarily from a 106 Bcf increase in net production from our Northeast Appalachia properties and a 140 Bcfe increase in net production from our Southwest Appalachia properties, which more than offset a 29 Bcf decrease in net production from our Fayetteville Shale properties and a combined 9 Bcfe decrease in net production from our East Texas and Arkoma Basin properties, which were divested in the first half of 2015. The increase in production in 2014 resulted primarily from a 103 Bcf increase in net production from our Northeast Appalachia properties, a 3 Bcfe increase in net production from our Southwest Appalachia properties and an 8 Bcf increase in net production from our Fayetteville Shale properties, which more than offset a combined 3 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. We produced 2,265 MBbls of oil in 2015, compared to 235 MBbls of oil in 2014 and 138 MBbls of oil in 2013. Our oil production has increased in 2015 and 2014 primarily due to the acquisition of natural gas and oil properties in Southwest Appalachia and our exploration activities in the Brown Dense. In 2015, we produced 10,702 MBbls of NGLs, compared to 231 MBbls and 50 MBbls of NGLs in 2014 and 2013, respectively, primarily due to the acquisition of natural gas and oil properties in Southwest Appalachia and our exploration activities in the Brown Dense.

Sales of natural gas and oil 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 periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas 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 swap agreements to counterparties with appropriate credit standings. As of December 31, 2015, we did not have any New York Mercantile Exchange, or NYMEX, commodity price hedges in place on our targeted 2016 natural gas production. As of February 23, 2016, we had NYMEX commodity price hedges in place on 37 Bcf of our targeted 2016 natural gas production. We intend to hedge additional future production volumes to the extent natural gas prices rise to levels that we believe will achieve 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 hedge position as of December 31, 2015.

Including the effect of hedges, we realized an average price of \$2.37 per Mcf for our natural gas production in 2015, compared to \$3.72 per Mcf in 2014 and \$3.65 per Mcf in 2013. Our hedging activities increased our average realized natural gas sales price by \$0.46 per Mcf in 2015, compared to a decrease of \$0.02 per Mcf in 2014 and an increase of \$0.48 per Mcf in 2013. Our average oil price realized was \$33.25 per barrel in 2015, compared to \$79.91 per barrel in 2014 and \$103.32 per barrel in 2013. Our average realized NGL price was \$6.80 per barrel in 2015, \$15.72 per barrel in 2014 compared to \$43.63 per barrel in 2013. None of our oil or NGL production was hedged during 2015, 2014 or 2013.

During 2015, the average price received for our natural gas production, excluding the impact of hedges, was approximately \$0.75 per Mcf lower than average NYMEX prices. Differences between NYMEX and price realized are due primarily to locational differences and transportation cost. As of December 31, 2015, we have attempted to mitigate the volatility of basis differentials by protecting basis on approximately 216 Bcf and 67 Bcf of our 2016 and 2017 production, respectively, and expected natural gas production through physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately (\$0.16) per Mcf and (\$0.20) per Mcf for 2016 and 2017, respectively. Additionally, we have financial hedges in place on 5 Bcf of our 2016 production at a weighted average basis differential of \$0.75 per Mcf.

Delivery Commitments. As of December 31, 2015, we had natural gas delivery commitments of 455 Bcf in 2016 and 198 Bcf in 2017 under existing agreements. These amounts are well below our forecasted 2016 natural gas production from our Fayetteville Shale, Northeast Appalachia and Southwest Appalachia divisions and anticipated 2017 production from our available reserves in our Fayetteville Shale, Northeast Appalachia and Southwest Appalachia divisions, 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 or 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 customers include major energy companies, utilities and industrial purchasers of natural gas. During the years ended December 31, 2015, 2014 and 2013, no single third-party purchaser accounted for 10% or more of our consolidated revenues.

Competition

All phases of the natural gas and oil industry are highly competitive. We compete in the acquisition of properties, the search for and development of reserves, the production and sale of natural gas and oil 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 and individual producers and operators. 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 for pipeline and other services to transport our product to market, particularly in the northeastern United States.

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 will achieve the goal of increasing competition, lessening preferential treatment and enhancing transparency in markets in which our natural gas production is sold. However, we do not believe that we will be disproportionately or regulatory affected as compared to other natural gas and oil producers and marketers by any action taken by the FERC or any other legislative body.

Regulation

The exploration and development of natural gas and oil resources and the transportation and sale of 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 or oil 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 and oil.

The exploration and development of 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 Services

We believe our Midstream Services segment is well-positioned to complement our E&P initiatives and to compete with other midstream providers for unaffiliated business. 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 gathering assets support our E&P operations and are currently concentrated in the Fayetteville Shale in Arkansas after the sale of our gathering assets in northeast Pennsylvania and Texas in the second quarter of 2015.

Our operating income from this segment was $583 million on revenues of $3.1 billion in 2015, compared to $361 million on revenues of $4.4 billion in 2014 and $325 million on revenues of $3.3 billion in 2013. Operating income in 2015 includes a $277 million net gain related to the sale of our northeast Pennsylvania and East Texas gathering assets. Excluding this gain, operating income decreased to $306 million in 2015 primarily due to a decrease in volumes gathered resulting from lower production volumes in the Fayetteville Shale and the sale of our northeast Pennsylvania gathering assets. Revenues decreased in 2015 primarily due to the prices received for volumes marketed. Revenues increased in 2014 primarily due to an increase in the prices received for volumes marketed and an increase in volumes marketed. Adjusted EBITDA generated by our Midstream Services segment was $368 million in 2015, compared to $418 million in 2014 and $377 million in 2013. The decrease in 2015 was primarily due to decreased gathered volumes. The increase in 2014 operating income and Adjusted EBITDA were primarily due to increased gathering revenues, partially offset by increased operating costs and expenses. Adjusted EBITDA is a non-GAAP measure. We refer you to "Management's Discussion and Analysis" in Item 1 of Part I of this Annual Report for a table that reconciles Adjusted EBITDA to net income (loss). During the years ended December 31, 2015, 2014 and 2013, no single third-party customer in our Midstream Services Segment accounted for 10% or more of our consolidated revenues.

Gas Gathering

Currently, our gas gathering activities are located predominantly in Arkansas and are related to the operation of our Fayetteville Shale asset. We invested approximately $58 million related to our gathering activities in 2015 and had gathering revenues of $491 million, compared to $144 million invested and revenues of $562 million in 2014 and $158 million invested and revenues of $516 million in 2013. During 2015, we divested our gathering assets in northeast Pennsylvania and East Texas. The divested gathering assets accounted for $21 million, $67 million and $48 million of our gathering revenues for the years ended December 31, 2015, 2014 and 2013, respectively.

During 2015, we gathered approximately 750 Bcf of natural gas in the Fayetteville Shale area, including 55 Bcf of natural gas from third-party operated wells. During 2014, we gathered approximately 812 Bcf of natural gas volumes in the Fayetteville Shale area, including 62 Bcf of natural gas from third-party operated wells. In 2013, we gathered approximately 790 Bcf of natural gas volumes in the Fayetteville Shale area, including 62 Bcf of natural gas from third-party wells. At the end of 2015, we had approximately 2,044 miles of pipe from the individual wellheads to the transmission lines and compression equipment representing in aggregate approximately 502,555 horsepower had been installed at 58 central point gathering facilities in the Fayetteville Shale.

Marketing

We attempt to capture opportunities related to the marketing and transportation of natural gas, oil and NGLs; although, our current marketing strategy primarily involves the marketing of our own natural gas production. Additionally, we manage portfolio and basis risk, acquire transportation rights on third-party pipelines and in limited circumstances, purchase third-party natural gas. During 2015, we marketed 1,127 Bcfe, compared to 904 Bcf in 2014 and 786 Bcf in 2013. Of the total gas volumes marketed, production from our affiliated E&P operations accounted for 97% in 2015, compared to 97% in 2014 and 96% in 2013. Our Midstream Services segment also marketed approximately 60% of our combined oil and NGL production for the year ended December 31, 2015.

Northeast Appalachia

In January 2015, we completed the purchase of certain natural gas and oil assets in northeast Pennsylvania and assumed short and long-term natural gas transportation agreements with Millennium Pipeline Company, L.L.C. with a total capacity of approximately 260,000 Mcf per day.

In January 2014, we entered into a precedent agreement with Transcontinental Gas Pipeline Company LLC that will provide additional firm transportation capacity for supplies of natural gas from northern Pennsylvania to markets along the Transco pipeline system stretching from the northeastern US in Transco's Zone 6, to Zone 5 and terminating in Zone 4. Subject to the receipt of regulatory approvals and satisfaction of other conditions, we agreed to enter a 15-year firm transportation agreement with a total capacity of approximately 44,000 Mcf per day on this project which is expected to be in service in the second half of 2017.

In May 2013, we entered into a precedent agreement with Columbia Gas Transmission, LLC for a project that expanded their existing system from Chester County, Pennsylvania to various interconnects throughout Pennsylvania, New Jersey, Maryland, and Virginia. Our volume on this project, which was placed in service October 2015, is 72,000 Mcf per day.

In March 2012, we entered into a precedent agreement with Constitution Pipeline Co. LLC for a proposed 121-mile pipeline connecting to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in Schoharie County, New York. Subject to the receipt of regulatory approvals and satisfaction of other conditions, we agreed to enter a 15-year firm transportation agreement with a total capacity of approximately 150,000 Mcf per day on this project. Constitution Pipeline Co. LLC has extended the range for the pipeline's target in-service date to late 2016 as a result of a longer than expected regulatory and permitting process. We have provided certain guarantees of a portion of our obligations under these agreements.

During 2011 and 2012, we entered into a number of short- and long-term firm transportation service agreements in support of our growing Northeast Appalachia operations in Pennsylvania. In March 2011, we entered into a precedent agreement with Millennium Pipeline Company, L.L.C. pursuant to which we entered into short- and long-term firm natural gas transportation services on Millennium's existing system. Expansions of the system were placed in-service in the second quarter of 2013 and the second quarter of 2014.

We have also executed firm transportation agreements with Tennessee Gas Pipeline Company ("TGP"), a subsidiary of Kinder Morgan Energy Partners, L.P., that increase our ability to move our Northeast Appalachia natural gas production in the short term to market as well as a precedent agreement for an expansion project that was placed in-service in November 2013 pursuant to which we have subscribed for approximately 100,000 Mcf per day of capacity. TGP's expansion project will expand its 300 Line in Pennsylvania to provide natural gas transportation from the Northeast Appalachia supply area to existing delivery points on the TGP system.

<u>Southwest Appalachia</u>

As part of our December 2014 acquisition of natural gas and oil assets in West Virginia and southwest Pennsylvania, we were assigned approximately 92,000 Mcf per day of capacity on the Columbia Gas Transmission pipeline. Additionally, we were assigned a precedent agreement with ET Rover Pipeline LLC for approximately 200,000 Mcf per day of capacity. ET Rover Pipeline LLC is constructing a new interstate pipeline to receive and transport natural gas from Marcellus and Utica production outlets to points of interconnection with Panhandle Eastern Pipe Line Company and ANR Pipeline, to interconnections in Michigan, to the Union Gas Dawn Hub and to certain off-system delivery points on Trunkline Zone 1A, and is anticipated to be in service by the second quarter 2017.

In December 2014, we also were assigned certain ethane transportation agreements that allow for the transport of our ethane production to both domestic and international markets.

In March 2015, we entered into a precedent agreement with Columbia Pipeline Group, Inc. that secured capacity of 500,000 Mcf per day on the Mountaineer XPress pipeline, with a portion of these volumes going to the Gulf Coast on the Gulf Xpress pipeline. The project is expected to be in service by late 2018 and will be routed through much of our core Southwest Appalachia acreage located in West Virginia.

At December 31, 2015, we had 450,000 Mcf per day of firm processing capacity with multiple processing providers located near our core acreage position in West Virginia. In the future, we have the option to increase our firm processing capacity by exercising options for the construction of incremental processing trains, the use of interruptible processing capacity, or consummating new processing agreements with new or existing service providers.

<u>Fayetteville Shale</u>

We are a "foundation shipper" on two pipeline projects serving the Fayetteville Shale. The Fayetteville Express Pipeline LLC, or FEP, is a 2.0 Bcf per day pipeline that is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. FEP was placed in service in January 2011. We have a maximum aggregate commitment of approximately 1,200,000 Mcf per day for an initial term of ten years from the in-service date. Texas Gas Transmission, LLC or Texas Gas, a subsidiary of Boardwalk Pipeline Partners, LP, constructed two pipeline laterals called the Fayetteville and Greenville Laterals, which also provide transportation for our Fayetteville Shale gas. We have maximum aggregate commitments of approximately 800,000 Mcf per day on the Fayetteville Lateral and 640,000 Mcf per day on the Greenville Lateral.

The Fayetteville and the Greenville Laterals and the FEP allow us to transport our natural gas to interconnecting pipelines that offer connectivity and marketing options to the eastern half of the United States. These interconnecting pipelines include Centerpoint, Natural Gas Pipeline, Mississippi River Transmission, Gulf South, Texas Gas, Tennessee Gas Pipeline, Trunkline, ANR, Columbia Gulf, Texas Eastern, and Sonat. We rely in part upon the Fayetteville and Greenville Laterals and the FEP to service our production from the Fayetteville Shale.

Demand Charges

As of December 31, 2015, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $8.9 billion, 38% 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 $960 million of that amount. Additionally, $100 million relates to demand charges under firm transportation agreements under which we have the option to reduce our commitment by 531 Bcf beginning in 2018.

We refer you to the risk factor "We have made significant investments in pipelines and gathering systems and contracts and in oilfield service businesses, including our drilling rig, 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."

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.

Regulation

The transportation of natural gas and oil are 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. 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 primarily consisted of real estate development activities. In 2013, we started construction on a corporate office complex located in Spring, Texas on 26 acres of commercial land that we purchased in 2012. The Company financed the construction of this complex through a construction agreement and lease arrangement. In January 2015, construction on the corporate office was completed and the Company commenced a lease with a term of approximately five years.

We sold no commercial real estate in 2015, 2014 or 2013.

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 against costs of clean-up operations, but 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. 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 the 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 2015, 2014 and 2013, oil accounted for less than 1% of our total production, although we expect this percentage to increase as we 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 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. The knowledge and expertise in fracturing techniques we have developed through our operations in the Fayetteville Shale and Northeast Appalachia are being utilized in our other operating areas, including Southwest Appalachia, the Sand Wash Basin and our Lower Smackover Brown Dense acreage and, in the future, may include our exploration program in New Brunswick, Canada. Successful hydraulic fracturing techniques are also expected to be critical to the development of other New Venture areas. 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 August 2015, the EPA released proposed additional regulations that would control methane and volatile organic compound emissions from certain oil and gas equipment and operations. The EPA also recently proposed 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 and proposed 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 being 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. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A final draft of the report was released for peer review and public comment in 2015.

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. In 2015, the provincial government in New Brunswick announced a moratorium on hydraulic fracturing until a list of conditions is met. The list of conditions is subjective, and although the provincial government has stated that it expects to make a decision on the moratorium by the end of 2016, we cannot predict whether or when it may be lifted. Unless and until the moratorium is lifted, we will not be able to continue with our program in New Brunswick.

In addition, concerns have been raised about the potential for earthquakes 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. 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.

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 could lead 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.

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. More recently, in 2015, the Obama Administration announced that the EPA is expected to finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025. EPA proposed such regulations in August 2015.

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. 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 that are not subject to extensive environmental regulation. If and when 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, 2015, we had 2,597 total employees. None of our employees were covered by a collective bargaining agreement at year-end 2015. We believe that our relationships with our employees are good. 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. We expect this reduction to be substantially complete by the end of the first quarter of 2016. Affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, amendments to outstanding equity awards to modify forfeiture provisions.

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.

"Adjusted EBITDA" Net income (loss) plus interest, taxes, depreciation, depletion and amortization and any non-cash impairment of natural gas and oil properties, (gain) loss on derivatives, excluding derivatives, settled, gain on sale of assets and certain one-time charges. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Reconciliation of Non-GAAP Measures" in Item 7 of Part II of this Annual Report for a table that reconciles Adjusted EBITDA with our net income (loss) from our audited financial statements.

"Analogous reservoir" Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

For additional information, see the SEC's definition in Rule 4-10(a) (2) 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.

"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.

"Downspacing" The process of drilling additional wells within a defined producing area to increase recovery of natural gas and oil from a known reservoir.

"E&P" Exploration for and production of natural gas and oil.

"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.

"Fracture stimulation" 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.

"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.

"Infill drilling" Drilling wells in between established producing wells to increase recovery of natural gas and oil 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.

“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.

“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 oil and gas reserves” Proved natural gas, oil and NGL reserves are those quantities of natural gas, oil and NGLs, which, 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.

"Tcf" One trillion cubic feet of natural gas.

"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: (1) tight sands, (2) coal beds, or (3) 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."

"Well spacing" The regulation of the number and location of wells over an oil or natural gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the regulatory conservation commission in the applicable jurisdiction. The order may be statewide in its application (subject to change for local conditions) or it may be entered for each field after its discovery. In the operational context, "well spacing" refers to the area attributable between producing wells within the scope of what is permitted under a regulatory order.

"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 natural gas liquids prices greatly affect our revenues, profitability, liquidity and growth and the value of our assets.

Our revenues, profitability, liquidity and growth and the value of our assets greatly depend upon prices for natural gas, oil and natural gas liquids. The markets for these commodities have been volatile, and we expect that volatility to continue. The prices of natural gas, oil and natural gas liquids 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 2015 and 2014, our production was approximately 92% and 100% natural gas, respectively, and during this period spot prices ranged from a high of $8.15 per Mcf in February 2014 to a low of $1.63 per Mcf in December 2015. These price changes are not predictable.

In our exploration and production business, lower natural gas, oil and natural gas liquids 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. See “Significant capital expenditures are required to replace our reserves and conduct our business.” 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 2015, we reported a non-cash impairment charge on our natural gas and oil properties of $7.0 billion, primarily resulting from a 41% decrease in trailing 12-month average first-day-of-the-month natural gas prices as of December 31, 2015, as compared to December 31, 2014, and the impairment of certain undeveloped leasehold interests. Current 2016 forward pricing will likely result in additional impairments to our natural gas and oil properties in the first quarter of 2016 ranging from approximately $300 million to $500 million, net of tax, when excluding future changes in costs excluded from amortization, with likely material impairments continuing beyond the first quarter. Further impairments in subsequent periods will occur if the trailing 12-month commodity prices continue to fall as compared to the average used in prior periods.

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

The dramatic drop in prices in the past two 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, which may result in lower production levels, and our workforce, which has caused us to incur significant expenses relating to terminations. Further price decreases could have similar consequences. Similarly, a rise in prices to levels experienced in 2013 and into the middle of 2014 could significantly increase our revenues, profits and cash flow, which could be used to expand capital investments and thus future production.

Significant capital expenditures are required to replace our reserves and conduct our business.

Our exploration, development and acquisition activities require substantial capital expenditures. We intend to fund our capital expenditures through net cash flows from operations. 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 natural gas liquids, our success in developing and producing new reserves and the other risk factors discussed herein. If we are unable to fund capital expenditures, we could experience a further curtailment of our exploration and production operations, a loss of properties and a decline in our natural gas, oil and natural gas liquids production and reserves. In particular, prices at the levels experienced in December 2015 and January 2016, should they continue, would not support any material new drilling or acquisitions.

If we are not able to replace reserves, we may not be able to grow or sustain production.

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 development, exploration or acquisition activities, our proved reserves and production will decline over time. In addition, approximately 7% of our total estimated proved reserves (by volume) as of December 31, 2015 were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Thus, our future natural gas and oil reserves and production, and therefore our cash flow and income, 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.

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 affect the market value of our senior notes and increase our corporate borrowing costs, including the interest rates charged under our credit facility and term loan credit facility. 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 such rating may be obtained from such rating agency. As of February 23, we were rated B1 by Moody’s, BB+ by Standard and Poor’s and BBB- 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 the posting of a letter of credit, could reduce our available cash or our liquidity under our revolving credit facility for other purposes. 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 material decrease in our liquidity.

Lower commodity prices may impair our ability to service our existing debt or refinance it when it becomes due.

As of December 31, 2015, we had $4.7 billion of debt outstanding, consisting principally of $3.9 billion in long-term senior notes maturing in various increments from 2017 to 2025, $750 million in a term loan due in 2018 and $116 million under our revolving credit agreement, which also matures in 2018. At current commodity price levels, our net cash flow from operations is substantially higher than our interest obligations under this debt, but further significant drops in 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. Our current credit agreements and indentures do not contain significant covenants restricting our operations and other activities, but future credit arrangements could impose such restrictions. 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.

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 operate within net cash flow and to invest capital in projects only if they are projected to generate a PVI of 1.3 or greater. 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 158,879 (including 158,231 net acres held on federal lands that are currently suspended by the Bureau of Land Management) net acres of our Fayetteville Shale acreage 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 100,787 and 91,572 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. To the extent we do not drill the wells, our rights to acreage can be lost.

Natural gas and oil drilling and producing operations 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 are dependent 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 pipeline;
- 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, 2015, we had long-term indebtedness of $4.7 billion, including borrowings of $116 million under our revolving credit facility and $750 million under our term loan credit agreement. The terms of the indentures relating to our outstanding senior notes, our credit facilities, and the master lease agreements relating to our drilling rigs and other equipment, 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 debt;
- making investments;
- creating liens on our assets; and
- selling assets.

Under our revolving credit facility and term loan facility, 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 any full cost ceiling impairments, certain non-cash hedging activities and our pension and other postretirement liabilities. Therefore, under our revolving credit facility, our adjusted capital structure as of December 31, 2015, was 38% debt and 62% equity. We were in compliance with all of the covenants of our revolving credit facility as of December 31, 2015. Although we do not anticipate any violations of our financial covenants, our ability to comply with these covenants are dependent upon 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 the 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 expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, 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, loss of use of our drilling rigs. 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 high of $3.19 in January 2015 and a low of $2.03 in November 2015 based on last-day-of-month settlement. We may not have sufficient funds to make such payments. 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, 2015, we had invested approximately $1.2 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, 2015, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately $8.9 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 recent drop in commodity prices has caused us to take much of this equipment out of service 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.

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 or complete announced dispositions, 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.

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 earthquakes to occur from the use of underground injection control wells, a predominant method for disposing of waste water from natural gas and oil activities. 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.

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, 2015, 47% of our total estimated proved reserves were attributable to properties located in the Appalachian Basin and 53% 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 natural gas liquids.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market natural gas, oil and NGLs and secure trained personnel.

Our ability to acquire additional prospects and to find 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 and oil 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 productive natural gas and oil properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. 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. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our financial condition, results of operations and cash flows.

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

United States and global economies may experience periods of turmoil and volatility from time to time, which may be characterized by diminished liquidity and credit availability, inability to access capital markets, high unemployment, unstable consumer confidence and diminished consumer spending. In recent periods, there has been significant downward pressure on natural gas, oil and NGL prices, and a continuation of that trend could continue or exacerbate that pressure. This would negatively impact our revenues, margins, profitability, operating cash flows, liquidity and financial condition. Such weakness or uncertainty could also cause our natural gas hedging arrangements or future oil or NGL hedges, if any, to become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Furthermore, our ability to collect receivables may be adversely impacted.

Historically, we have used cash flows from operations, borrowings under our credit facility and proceeds from capital market transactions to fund capital expenditures. Volatility in U.S. and global financial markets, including market disruptions, limited liquidity, and interest rate volatility, may result in our inability to obtain needed capital on acceptable terms or at all and may increase our cost of financing. We have a credit facility with lender commitments totaling $2.0 billion, which may be increased up to a total of $2.5 billion upon agreement with participating lenders, and a term loan credit agreement with lender commitments for an additional $750 million. We also have $3.9 billion in senior notes maturing in various increments from 2017 to 2025. In the future, regardless of our company’s situation, conditions in financial markets may limit our ability to access adequate funding under our credit facility if our lenders are unwilling or unable to meet their funding obligations or increase their commitments under the credit facility. Due to these and other factors, we cannot be certain that funding, if needed, will be available to the extent required or on terms we find acceptable. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, fund our capital program and commitments, complete new property acquisitions to replace reserves, take advantage of business opportunities, respond to competitive pressures, or refinance debt obligations as they come due. Should any of the above risks occur, they could have a material adverse effect on our financial condition, results of operations and cash flows.

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. In order to conduct operations in compliance with these laws and regulations, we must 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.

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 natural gas liquids we produce.

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. More recently, in January 2015, the Obama Administration announced that the EPA is expected to finalize in 2016 new regulations that will set methane emission standards for new and modified natural gas and oil production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and natural gas sector by up to 45% from 2012 levels by 2025. The EPA proposed such regulations in 2015.

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. 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.

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, that 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 expenditures

In November 2013, the CFTC 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. If finalized, the position limits rule and its companion rule on aggregation among entities under common ownership or control 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 recently adopted mandatory margin requirements on uncleared swaps between swap dealers and certain other counterparties. 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 will also 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.

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 expenditures, 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 and oil 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.

Derivative transactions may limit our potential gains and involve other risks.

To manage our exposure to price risk, we currently, and may in the future, enter into derivative arrangements, utilizing commodity derivatives with respect to a portion of our future production. The goal of entering into such derivative agreements is to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if natural gas, oil and natural gas liquids prices rise above the price established by the hedge.

In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our futures contracts fail to perform on their contract obligations; or
- an event materially impacts natural gas, oil or NGL prices or the relationship between the hedged price index and the natural gas, oil or NGL sales price.

We cannot assure you that any derivative transaction we may enter into will adequately protect us from declines in the prices of natural gas, oil or natural gas liquids. Likewise, these transactions may limit our potential gains should prices of natural gas, oil or natural gas liquids rise. Where we choose not to engage in derivative transactions in the future, we may be more adversely affected by changes in natural gas, oil or natural gas liquids prices than our competitors who engage in derivative transactions. Lower natural gas, oil and NGL prices may also negatively impact our ability to enter into derivative contracts at favorable prices.

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 has been proposed in recent years by members of the U.S. Congress and by the President in his fiscal year 2016 budget proposal. These changes have included, 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.

It is unclear whether these or similar changes will be enacted. 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.

Our Canadian exploration and production activities are subject to different risks and uncertainties, different from or in addition to those we face in our U.S. operations.

In addition to the various risks associated with our U.S. operations, we are subject to risks and uncertainties related to our Canadian exploration and production activities, including risks related to increases in taxes and governmental royalties, changes in laws and policies governing operations of foreign-based companies, restrictions on imports and exports, expropriation of property, cancellation of contract rights, environmental protection controls, environmental compliance requirements and laws pertaining to workers' health and safety. Consequently, our exploration, development and production activities in Canada could be substantially affected by factors beyond our control. In addition, the rights of aboriginal peoples, called First Nations in Canada, are not clear. Our operations in New Brunswick have been subject to local protests, causing several temporary interruptions to our exploration activities. In December 2014, New Brunswick's provincial government announced its intent to impose a moratorium on hydraulic fracturing in the province, and, on March 27, 2015, the provincial legislature approved enabling legislation. We have been granted an extension of our licenses. The provincial government has announced a list of conditions that must be met before the moratorium can be lifted, but because these conditions are subjective and the government has discretion whether to grant an extension, we cannot predict the duration of the moratorium or whether it will continue beyond the expiration of the licenses, as their terms have been extended. Unless and until the moratorium is lifted, we will not be able to continue with our program in New Brunswick. If the licenses expire before the moratorium is lifted or we can complete our program, we may be required to write off our investment.

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.

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, 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.

In January 2015, we issued 30.0 million shares of common stock and 34.5 million depositary shares representing the 1/20th interest in our 6.25% Series B Mandatory Preferred Stock, which will convert into a minimum of approximately 64 million or a maximum of 75 million shares of common stock by January 2018, to refinance a portion of the debt we incurred to purchase acreage in West Virginia and southwest Pennsylvania. 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES

The summary of our oil and natural gas reserves as of fiscal year-end 2015 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed "2015 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 Note 4 to the consolidated financial statements. 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, 2015:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Appalachia:				
Northeast (1)	196,166	168,753	106,518	101,582
Southwest (2)	348,604	193,582	342,223	231,516
Fayetteville Shale (3)	472,818	288,569	1,059,158	669,072
New Ventures:				
USA New Ventures – Brown Dense (4)	256,287	196,598	4,903	4,493
USA New Ventures – Sand Wash Basin (5)	349,796	243,493	11,181	7,985
USA New Ventures – Other (6)	722,248	504,526	–	–
Canada New Ventures (7)	2,716,758	2,716,758	–	–
	5,062,677	4,312,279	1,523,983	1,014,648

(1) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 30,172 net acres in 2016, 57,724 net acres in 2017 and 12,891 net acres in 2018.

(2) Assuming successful wells are not drilled to develop the acreage and leases are not extended leasehold expiring over the next three years will be 36,934 net acres in 2016, 42,034 net acres in 2017 and 12,604 net acres in 2018. Of this acreage, 16,160 net acres in 2016, 15,262 net acres in 2017 and 1,990 net acres in 2018 can be extended for an average of an additional 4.8 years.

(3) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 164 net acres in 2016, 453 net acres in 2017 and 31 net acres in 2018 (excluding 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management). Includes 31,413 net undeveloped acres and 170,743 net developed acres in the Arkoma Basin that have previously been reported as a component of our conventional Arkoma acreage.

(4) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 58,849 net acres in 2016, 68,790 net acres in 2017 and 67,528 net acres in 2018.

(5) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 85,767 net acres in 2016, 35,883 net acres in 2017 and 55,918 net acres in 2018.

(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 206,567 net acres in 2016, 69,447 net acres in 2017 and 22,286 net acres in 2018.

(7) Assuming successful wells are not drilled to develop the acreage and our exploration license agreements are not extended, leasehold expiring over the next three years will be 48,960 net acres in 2016, 148,480 net acres in 2017 and 800 net acres in 2018.

Producing wells as of December 31, 2015:

	Natural Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Appalachia:							
Northeast [1]	774	407	–	–	774	407	424
Southwest	1,085	859	–	–	1,085	859	994
Fayetteville Shale	4,268	2,971	–	–	4,268	2,971	3,756
New Ventures	12	9	8	8	20	17	20
	6,139	4,246	8	8	6,147	4,254	5,194

(1) Includes 316 gross natural gas wells in which we own an overriding royalty interest.

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

	Exploratory[1]					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2015	3.0	3.0	–	–	3.0	3.0
2014	12.0	11.9	–	–	12.0	11.9
2013	8.0	7.8	1.0	1.0	9.0	8.8

	Development[1]					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2015	427.0	344.4	–	–	427.0	344.4
2014	572.0	466.1	–	–	572.0	466.1
2013[2]	527.0	468.8	3.0	1.5	530.0	470.3

(1) We have not drilled any exploratory or development wells in Canada in the past three years.

(2) 2013 dry wells include 2 gross wells in the Fayetteville Shale that were plugged and abandoned after being spud due to changes in the development plans.

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, 2015: [1,2]

	Gross	Net
Drilling:		
Exploratory	1	1
Development	47	47
Total	48	48
Completing:		
Exploratory	1	1
Development	154	130
Total	155	131
Drilling & Completing:		
Exploratory	2	2
Development	201	177
Total	203	179

(1) As of December 31, 2015, we did not have any drilling activities in Canada.

(2) Includes 41 wells that are waiting on pipeline or production facilities.

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,		
	2015	2014	2013
Natural Gas			
Production (Bcf):			
Northeast Appalachia	**360**	254	151
Southwest Appalachia	**67**	2	–
Fayetteville Shale	**465**	494	486
Other	**7**	16	19
Total	**899**	766	656
Average gas price per Mcf, excluding hedges:			
Northeast Appalachia	**$ 1.62**	$ 3.48	$ 3.25
Southwest Appalachia	**1.92**	3.61	–
Fayetteville Shale	**2.12**	3.86	3.13
Total	**$ 1.91**	$ 3.74	$ 3.17
Average realized gas price per Mcf, including hedges	**$ 2.37**	$ 3.72	$ 3.65
Oil			
Production (MBbls):			
Southwest Appalachia	**2,036**	45	–
Other	**229**	190	138
Total	**2,265**	235	138
Average oil price per Bbl:			
Southwest Appalachia	**$ 31.80**	$ 41.28	$ –
Other	**46.21**	89.04	103.32
Total	**$ 33.25**	$ 79.91	$ 103.32
NGL			
Production (MBbls):			
Southwest Appalachia	**10,640**	182	–
Other	**62**	49	50
Total	**10,702**	231	50
Average NGL price per Bbl:			
Southwest Appalachia	**$ 6.76**	$ 10.44	$ –
Other	**14.51**	35.22	43.63
Total	**$ 6.80**	$ 15.72	$ 43.63
Total Production (Bcfe):			
Northeast Appalachia	**360**	254	151
Southwest Appalachia	**143**	3	–
Fayetteville Shale	**465**	494	486
Other	**8**	17	20
Total	**976**	768	657
Average Production Cost			
Cost per Mcfe, excluding ad valorem and severance taxes:			
Northeast Appalachia	**$ 0.71**	$ 0.83	$ 0.80
Southwest Appalachia	**1.39**	1.17	–
Fayetteville Shale	**0.91**	0.92	0.86
Total	**$ 0.92**	$ 0.91	$ 0.86

During 2015, 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 Note 4 to the consolidated financial statements in Item 8 to 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, 2015, our Midstream Services segment had 2,044 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. 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 examination 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. See "Litigation" in Note 9, "Commitments and Contingencies" in the consolidated financial statements for further details on our current legal proceedings.

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.

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.

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 23, 2016, the closing price of our common stock trading under the symbol "SWN" was $6.63 and we had 3,416 stockholders of record, respectively. The following table presents the high and low sales prices for closing market transactions for our common stock trading under the symbol "SWN" as reported on the NYSE.

	Range of Market Prices					
Quarter Ended	**2015**		2014		2013	
March 31	**$ 27.97**	**$ 21.63**	$ 46.57	$ 38.01	$ 38.86	$ 32.09
June 30	**$ 29.25**	**$ 22.49**	$ 48.93	$ 44.33	$ 39.58	$ 34.97
September 30	**$ 22.17**	**$ 12.11**	$ 44.99	$ 34.95	$ 39.91	$ 36.38
December 31	**$ 13.59**	**$ 5.15**	$ 36.50	$ 27.24	$ 40.18	$ 35.16

We do not currently pay quarterly cash 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, 2015:

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
December 1 - 31, 2015	71,911	$	7.69	n/a	n/a
Total fourth-quarter 2015:	71,911	$	7.69	n/a	n/a

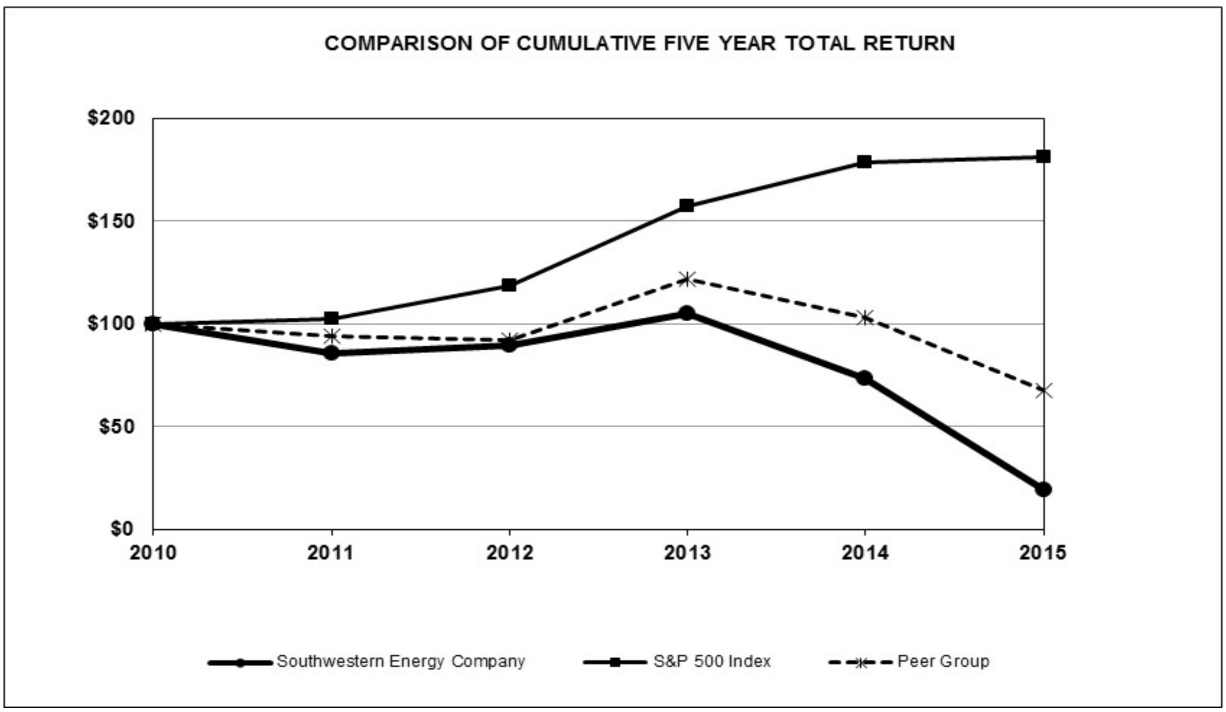
(1) Reflects shares retired by us to satisfy applicable tax withholding obligations due on employee stock plan share issuances. All changes in common stock in treasury in 2015 were due to purchases and sales of shares held on behalf of participants in a non-qualified deferred compensation supplemental retirement savings plan.

Recent Sales of Unregistered Equity Securities

We did not sell any unregistered equity securities during 2015, 2014 or 2013. 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, 2015.

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 was expanded in 2015 to reflect the companies whose performance metrics are currently used in determining our annual incentive awards and includes 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, 2010, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.



		12/31/10		12/31/11		12/31/12		12/31/13		12/31/14		**12/31/15**
Southwestern Energy Company	$	100	$	85	$	89	$	105	$	73	$	**19**
S&P 500 Index		100		102		118		157		178		**181**
Peer Group		100		94		92		122		103		**68**

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, 2015. 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.”

	2015	2014	2013	2012	2011
	(in millions except shares, per share, stockholder data and percentages)				
Financial Review					
Operating revenues:					
Exploration and production	**$ 2,074**	$ 2,862	$ 2,404	$ 1,964	$ 2,099
Midstream services	**3,119**	4,358	3,347	2,363	2,860
Other	**–**	–	–	3	3
Intersegment revenues	**(2,060)**	(3,182)	(2,380)	(1,600)	(2,010)
	3,133	4,038	3,371	2,730	2,952
Operating costs and expenses:					
Marketing purchases – midstream services	**852**	980	782	592	709
Operating and general and administrative expenses	**935**	648	519	420	399
Depreciation, depletion and amortization	**1,091**	942	787	811	705
Impairment of natural gas and oil properties	**6,950**	–	–	1,940	–
Gain on sale of assets, net	**(283)**	–	–	–	–
Taxes, other than income taxes	**110**	95	79	68	66
	9,655	2,665	2,167	3,831	1,879
Operating income (loss)	**(6,522)**	1,373	1,204	(1,101)	1,073
Interest expense, net	**56**	59	42	35	24
Other income (loss), net	**(30)**	(4)	2	1	–
Gain (loss) on derivatives	**47**	139	26	(15)	2
Income (loss) before income taxes	**(6,561)**	1,449	1,190	(1,150)	1,051
Provision (benefit) for income taxes:					
Current	**(2)**	21	(11)	19	4
Deferred	**(2,003)**	504	497	(462)	409
	(2,005)	525	486	(443)	413
Net income (loss)	**$ (4,556)**	$ 924	$ 704	$ (707)	$ 638
Mandatory convertible preferred stock dividend	**106**	–	–	–	–
Net income (loss) Attributable to Common Stock	**$ (4,662)**	$ 924	$ 704	$ (707)	$ 638
Return on equity	**(204.3%)**	19.8%	19.4%	(23.3%)	16.1%
Net cash provided by operating activities	**$ 1,580**	$ 2,335	$ 1,909	$ 1,654	$ 1,740
Net cash used in investing activities	**$ (1,638)**	$ (7,288)	$ (2,216)	$ (1,907)	$ (2,025)
Net cash provided by financing activities	**$ 20**	$ 4,983	$ 277	$ 291	$ 284
Common Stock Statistics					
Earnings per share:					
Net income (loss) attributable to common stockholders – Basic	**$ (12.25)**	$ 2.63	$ 2.01	$ (2.03)	$ 1.84
Net income (loss) attributable to common stockholders – Diluted	**$ (12.25)**	$ 2.62	$ 2.00	$ (2.03)	$ 1.82
Book value per average diluted share	**$ 6.00**	$ 13.23	$ 10.32	$ 8.71	$ 11.34
Market price at year-end	**$ 7.11**	$ 27.29	$ 39.33	$ 33.41	$ 31.94
Number of stockholders of record at year-end	**3,415**	3,271	3,259	3,122	3,083
Average diluted shares outstanding	**380,521,039**	352,410,683	351,101,452	348,610,503	349,921,413

	2015		2014		2013		2012		2011
Capitalization (in millions)										
Total debt	**$**	**4,729**	$	6,967	$	1,951	$	1,669	$	1,343
Total equity		**2,282**		4,662		3,622		3,036		3,969
Total capitalization	**$**	**7,011**	$	11,629	$	5,573	$	4,705	$	5,312
Total assets	**$**	**8,110**	$	14,925	$	8,048	$	6,738	$	7,903
Capitalization ratios:										
Debt		**67%**		60%		35%		35%		25%
Equity		**33%**		40%		65%		65%		75%
Capital Investments (in millions) [(1)]										
Exploration and production		**2,258**		7,254		2,052		1,861		1,978
Midstream services		**167**		144		158		165		161
Other		**12**		49		25		55		68
	$	**2,437**	$	7,447	$	2,235	$	2,081	$	2,207
Exploration and Production										
Natural gas:										
Production, Bcf		**899**		766		656		565		499
Average realized price per Mcf, including hedges	**$**	**2.37**	$	3.72	$	3.65	$	3.44	$	4.18
Average price per Mcf, excluding hedges	**$**	**1.91**	$	3.74	$	3.17	$	2.34	$	3.56
Oil:										
Production, MBbls		**2,265**		235		138		83		97
Average price per barrel	**$**	**33.25**	$	79.91	$	103.32	$	101.54	$	94.08
NGL:										
Production, MBbls		**10,702**		231		50		–		–
Average price per barrel	**$**	**6.80**	$	15.72	$	43.63	$	–	$	–
Total production, Bcfe		**976**		768		657		565		500
Lease operating expenses per Mcfe	**$**	**0.92**	$	0.91	$	0.86	$	0.80	$	0.84
General and administrative expenses per Mcfe	**$**	**0.21**	$	0.24	$	0.24	$	0.26	$	0.27
Taxes, other than income taxes per Mcfe	**$**	**0.10**	$	0.11	$	0.10	$	0.10	$	0.11
Proved reserves at year-end:										
Natural gas, Bcf		**5,917**		9,809		6,974		4,017		5,887
Oil, MMBbls		**8.8**		37.6		0.4		0.2		1
NGLs, MMBbls		**40.9**		118.7		–		–		–
Total reserves, Bcfe		**6,215**		10,747		6,976		4,018		5,893
Midstream Services										
Volumes marketed, Bcfe		**1,127**		904		786		676		611
Volumes gathered, Bcf		**799**		963		900		846		746

(1) Capital investments include a decrease of $33 million for 2015, an increase of $155 million for 2014, decreases of $25 million and $37 million for 2013 and 2012, respectively, and an increase of $4 million for 2011 related to the change in accrued expenditures between years.

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. The words "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 identify forward-looking statements. The Company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. 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" or "Southwestern") is an independent energy company engaged in natural gas and oil 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 Services. We operate principally in two segments: E&P and Midstream Services.

Our primary business is the exploration, development and production of natural gas and oil. Our current operations are principally 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, 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. Collectively, we refer to our properties located in Pennsylvania and West Virginia as the "Appalachian Basin." Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. We also actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which we refer to as "New Ventures." Under our New Ventures operations, we have exploration and production activities ongoing in Colorado and Louisiana, along with other areas in which we are currently exploring for new development opportunities. We operate drilling rigs and provide oilfield products and services, principally serving our exploration and production operations, though the level of these services in 2016 will depend upon our capital investing for the year. Our natural gas gathering and marketing activities primarily support our E&P activities in Arkansas, Pennsylvania, Louisiana and West Virginia.

We are focused on providing long-term growth in the net asset value per share of our business. Historically, the vast majority of our operating income and cash flow has been derived from the production associated with our E&P business. However, in 2015, depressed commodity prices significantly decreased our E&P results of operations. The price we expect to receive for our production is a critical factor in the capital investments we make in order to develop our properties. In 2016, we expect to have decreased activity in the Appalachian Basin and the Fayetteville Shale as a result of the lower commodity price environment. We anticipate adjusting our activity levels throughout our portfolio and are targeting a capital investment program aligned with the cash flow expected to be generated during the year. Natural gas prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas, which in turn determines the sales prices for our production. Going forward, we will be impacted by crude oil and natural gas liquids ("NGLs") prices which have been volatile and have recently declined significantly. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. Current 2016 forward pricing will likely result in additional impairments to our natural gas and oil properties in the first quarter of 2016 ranging from approximately $300 million to $500 million, net of tax, when excluding future changes in costs excluded from amortization, with likely material impairments continuing beyond the first quarter.

Recent Financial and Operating Results

In 2015, our net loss attributable to common stock was $4,662 million, or ($12.25) per diluted share, down from net income of $924 million, or $2.62 per diluted share, in 2014. Our net income was $704 million, or $2.00 per diluted share, in 2013. In 2015, we incurred non-cash impairments of our natural gas and oil properties totaling $6,950 million, or $4,287 million net of taxes, that resulted from a significant decline in natural gas prices during 2015.

In 2015, our natural gas and liquids production increased 27% to 976 Bcfe, up from 768 Bcfe in 2014. The 208 Bcfe increase in our 2015 production resulted from a 140 Bcfe increase in net production from our Southwest Appalachia properties, a 106 Bcf increase in net production from our Northeast Appalachia properties and was offset by a 38 Bcfe decrease in net production from our Fayetteville Shale and other properties. In 2014, our natural gas and liquids production increased to 768 Bcfe, up from 657 Bcfe in 2013. The 111 Bcfe increase in our 2014 production resulted from a 103 Bcf increase in net production from our Northeast Appalachia properties and an 8 Bcf increase in net production from our Fayetteville Shale properties.

Our year-end reserves decreased 42% in 2015 to 6,215 Bcfe, down from 10,747 Bcfe at the end of 2014 and 6,976 Bcfe at the end of 2013. The overall decrease in total estimated proved reserves in 2015 was primarily due to downward price revisions associated with decreased commodity prices, partially offset by upward performance revisions in Northeast and Southwest Appalachia. The overall increase in total estimated proved reserves in 2014 was primarily due to the acquisition of approximately 413,000 net acres in Southwest Appalachia which increased reserves by 33%, our successful drilling programs in the Fayetteville Shale and Northeast Appalachia and upward performance revisions in Northeast Appalachia where reserves grew 63% from 2013.

Our E&P segment operating loss was $7,104 million in 2015, down from operating income of $1,013 million in 2014. The operating loss in 2015 included non-cash impairments of natural gas and oil properties totaling $6,950 million. Excluding the non-cash impairments, operating income in 2015 decreased $1,167 million from 2014 as the revenue impact of our 27%, or 208 Bcfe, increase in production was more than offset by a 36%, or $1.35, decrease in our average realized natural gas price and a $379 million increase in operating costs and expenses that resulted from our production growth. Operating income was $1,013 million in 2014, up from operating income of $879 million in 2013. Operating income in 2014 increased $134 million over 2013 as the revenue impact of our 17%, or 111 Bcfe, increase in production and 2%, or $0.07, increase in our average realized natural gas price more than offset the $324 million increase in operating costs that resulted from our production growth. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $27 and $21 million in operating income for the years ended December 31, 2014 and 2013, respectively.

Operating income for our Midstream Services segment was $583 million in 2015, up from $361 million in 2014 and $325 million in 2013. Operating income for our Midstream Services segment increased in 2015 due to a $277 million net gain on sale of assets and a $13 million decrease in operating costs and expenses, exclusive of marketing purchase costs, partially offset by a decrease of $71 million in gathering revenues, which resulted from decreased volumes gathered. Volumes gathered decreased to 799 Bcf in 2015, compared to 963 Bcf in 2014. In the second quarter of 2015, we sold our northeast Pennsylvania and East Texas gathering assets that accounted for $13, $35 and $23 million in operating income for the years ended December 31, 2015, 2014 and 2013, respectively. A net gain of $277 million was recognized and is included in gain on sale of assets, net in the consolidated statement of operations. Operating income for our Midstream Services segment increased in 2014 due to an increase of $46 million in gathering revenues and a $12 million increase in the margin generated from our natural gas marketing activities, which was partially offset by a $22 million increase in operating costs and expenses, exclusive of natural gas purchase costs, that resulted from our growth in volumes gathered. Volumes gathered grew to 963 Bcf in 2014 compared to 900 Bcf in 2013.

We had total capital investments of $2.4 billion in 2015, compared to $7.4 billion in 2014 and $2.2 billion in 2013. Of our total capital investments, $2.3 billion was invested in our E&P segment in 2015, which included $533 million related to acquisitions, compared to $7.3 billion in 2014, which included $5.2 billion primarily related to the December 2014 acquisition of certain oil and natural gas assets in Southwest Appalachia from Chesapeake Energy Corporation (the "Chesapeake Property Acquisition"), and $2.1 billion in 2013, which included $96 million primarily related to the acquisition of properties in Northeast Appalachia. Our Midstream Services capital investments for 2015 included $109 million related to the acquisition from WPX.

Outlook

We are exercising capital discipline by aligning our 2016 capital investing program within our expected cash flow. We will also look for opportunities to strengthen our balance sheet, maximize margins in each core area of our business and continue to seek alternative means to further our knowledge of our asset base. We believe that 2016 will be a challenging year for our business due to the depressed commodity price environment and continued uncertainty of natural gas and oil prices in the United States. However, we expect that our resource base, financial flexibility and disciplined investment of capital will position us for success when commodity prices ultimately recover.

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

	For the years ended December 31,		
	2015	2014	2013
Revenues (in millions)	**$ 2,074**	$ 2,862	$ 2,404
Impairment of natural gas and oil properties (in millions)	**$ 6,950**	$ –	$ –
Operating costs and expenses (in millions)	**$ 2,228**	$ 1,849	$ 1,525
Operating income (loss) (in millions)	**$ (7,104)**	$ 1,013	$ 879
Gain on derivatives (in millions) (1)	**$ 206**	$ 9	$ 5
Gas production (Bcf)	**899**	766	656
Oil production (MBbls)	**2,265**	235	138
NGL production (MBbls)	**10,702**	231	50
Total production (Bcfe)	**976**	768	657
Average realized gas price per Mcf, including hedges (2)	**$ 2.37**	$ 3.72	$ 3.65
Average realized gas price per Mcf, excluding hedges	**$ 1.91**	$ 3.74	$ 3.17
Average oil price per Bbl	**$ 33.25**	$ 79.91	$ 103.32
Average NGL price per Bbl	**$ 6.80**	$ 15.72	$ 43.63
Average unit costs per Mcfe:			
Lease operating expenses	**$ 0.92**	$ 0.91	$ 0.86
General & administrative expenses	**$ 0.21**	$ 0.24	$ 0.24
Taxes, other than income taxes	**$ 0.10**	$ 0.11	$ 0.10
Full cost pool amortization	**$ 1.00**	$ 1.10	$ 1.08

(1) Represents the gain (loss) on derivatives, settled, associated with derivatives not designated for hedge accounting.

(2) Including the gain (loss) on derivatives excluding derivatives, settled effects of commodity hedging contracts not designated for hedge accounting, results in an average price of $2.20, $3.90 and $3.68 for the years ended December 31, 2015, 2014 and 2013, respectively.

Revenues

Revenues for our E&P segment were down $788 million, or 28%, in 2015 compared to 2014. A decrease in the price realized from the sale of our natural gas production decreased revenue by $1,647 million in 2015, partially offset by an increase of $497 million due to higher natural gas production volumes and an increase of $235 million in hedge settlement proceeds. Additionally, there was a $328 million increase due to increased liquids production related to our Southwest Appalachia property acquisition partially offset by a $201 million decrease due to decreased liquids pricing. E&P revenues were up $458 million, or 19%, in 2014 compared to 2013. Higher natural gas production volumes in 2014 increased revenue by $403 million and higher realized prices for our natural gas production increased revenue by $55 million. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $15, $70 and $68 million of our gas and oil revenues for the years ended December 31, 2015, 2014 and 2013, respectively. In 2016, we expect to have decreased activity in our Appalachian Basin and Fayetteville Shale assets as a result of the lower commodity price environment.

Production

In 2015, our natural gas and liquids production increased 27% to 976 Bcfe, up from 768 Bcfe in 2014, and was produced entirely by our properties in the United States. The 208 Bcfe increase in our 2015 production resulted from a 140 Bcfe increase in net production from our Southwest Appalachia properties, a 106 Bcf increase in net production from our Northeast Appalachia properties, partially offset by 29 Bcf and 9 Bcfe decreases in net production in our Fayetteville Shale and other properties, respectively. In 2014, our natural gas and liquids production increased to 768 Bcfe, up from 657 Bcfe in 2013. The 111 Bcfe increase in our 2014 production resulted from a 103 Bcf increase in net production from our Northeast Appalachia properties and an 8 Bcfe increase in net production in our Fayetteville Shale and other properties. Our net production from Northeast Appalachia was 360 Bcf in 2015, up from 254 Bcf in 2014 and 151 Bcf in 2013. Our net production from Southwest Appalachia was 143 Bcfe in 2015, up from 3 Bcfe in 2014; we owned no properties in this area before late December 2014. Our net production from the Fayetteville Shale was 465 Bcf in 2015, down from 494 Bcf in 2014 and 486 Bcf in 2013.

Natural gas accounted for approximately 92%, 100% and 100% of our total production for the years ended December 31, 2015, 2014 and 2013, respectively. Oil and NGLs accounted for 1% and 7%, respectively, of our total production for the year ended December 31, 2015.

Our ability to discover, develop and produce reserves is dependent upon a number of factors, many of which are beyond our control, including the availability of capital, availability of transportation, weather, the timing and extent of changes in natural gas and oil prices and competition. There are also many risks inherent in the discovery, development and production of natural gas and oil. We refer you to "Risk Factors" in Item 1A of Part I of this Annual Report for a discussion of these risks and the impact they could have on our financial condition and results of operations.

Commodity Prices

The average price realized for our natural gas production, including the effects of hedges, decreased 36% to $2.37 per Mcf in 2015, compared to an increase of 2% in 2014 to $3.72 per Mcf from 2013 levels. The decrease in 2015 was the result of a $1.83 decrease in the average natural gas price, excluding hedges, partially offset by higher proceeds from our hedging activities in 2015 as compared to 2014. The increase in 2014 compared to 2013 was primarily the result of increased natural gas prices as our hedging activities marginally decreased our average realized price. In 2015, our hedging activities increased the average natural gas sales price we realized by $0.46 per Mcf, compared to a decrease of $0.02 per Mcf in 2014 and an increase of $0.48 per Mcf in 2013. Disregarding the impact of hedges, the average realized sales price we received for our natural gas production in 2015 was $1.83 per Mcf lower than 2014 and $0.75 lower than the average monthly NYMEX settlement price for 2015.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices due to heating content of the gas, locational basis differentials, transportation charges 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.

We periodically 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 5 to the consolidated financial statements, and our hedge risk factor for additional discussion about our derivatives and risk management activities.

As of December 31, 2015, we have attempted to mitigate the volatility of basis differentials by protecting basis on approximately 216 Bcf and 67 Bcf of our 2016 and 2017 production, respectively, and expected natural gas production through physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately ($0.16) per Mcf and ($0.20) per Mcf for 2016 and 2017, respectively. Additionally, we have financial hedges in place on 5 Bcf of our 2016 production at a weighted average basis differential of $0.75 per Mcf.

We realized an average sales price of $33.25 per barrel for our oil production for the year ended December 31, 2015, down approximately 58% from the prior year. The 2014 average realized price of $79.91 per barrel was down 23% from 2013. We did not hedge our 2015, 2014 or 2013 oil production. We realized an average sales price of $6.80 per barrel for our NGL production for the year ended December 31, 2015, down approximately 57% from the prior year. The 2014 average realized price of $15.72 per barrel was down 64% from 2013. We did not hedge our 2015, 2014, or 2013 NGL production.

Operating Income

Our E&P segment operating loss was $7,104 million in 2015, down from an operating income of $1,013 million in 2014. The operating loss in 2015 included non-cash impairments of natural gas and oil properties totaling $6,950 million. Excluding the non-cash impairments, operating income in 2015 decreased $1,167 million over 2014 as the revenue impact of our 27%, or 208 Bcfe, increase in production was more than offset by a 36%, or $1.35, decrease in our average realized natural gas price and a $379 million increase in operating costs and expenses that resulted from our production growth. E&P segment operating income was $1,013 million in 2014, up from operating income of $879 million in 2013. Operating income in 2014 increased $134 million over 2013 as the revenue impact of our 17%, or 111 Bcfe, increase in production and 2%, or $0.07, increase in our average realized natural gas prices more than offset the $324 million increase in operating costs and expenses that resulted from our significant production growth. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $27 and $21 million of our operating income (loss) for the years ended December 31, 2014 and 2013, respectively.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.92 in 2015, compared to $0.91 in 2014 and $0.86 in 2013. Lease operating expenses per unit of production increased in 2015 primarily due to an increase in gathering and processing charges associated with our Southwest Appalachia operations. Lease operating expenses per unit of production increased in 2014 compared to 2013 primarily due to an increase in gathering and compression charges.

General and administrative expenses for the E&P segment were $0.21 per Mcfe in 2015, down from $0.24 per Mcfe in 2014 and 2013. The decrease in general and administrative costs per Mcfe in 2015 was primarily due to an increase in production volumes. In total, general and administrative expenses for the E&P segment were $207 million in 2015, $182 million in 2014 and $157 million in 2013. The increase in general and administrative expenses in 2015 was primarily a result of increased personnel and technological costs associated with the expansion of our E&P operations, due to the acquisition of our Southwest Appalachia assets, and accounted for $21 million, or 85%, of the 2015 increase. The increase in general and administrative expenses in 2014 was primarily due to increased personnel cost, information system related costs and training costs, offset slightly by decreased professional fees. This net increase accounted for $22 million, or 88%, of the 2014 increase. Our E&P employees decreased by 155 during 2015 as compared to 132 employees added in 2014. 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 which should be substantially complete by the end of the first quarter of 2016. We expect to record a pre-tax charge to earnings in the first quarter of 2016 of approximately $60 to $70 million.

Taxes other than income taxes per Mcfe were $0.10, $0.11 and $0.10 in 2015, 2014 and 2013, respectively. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged $1.00 per Mcfe for 2015, $1.10 per Mcfe for 2014 and $1.08 per Mcfe for 2013. 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 tests, 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 $3.7 billion at December 31, 2015, compared to $4.6 billion in 2014 and $1.0 billion in 2013. The decrease in unevaluated costs since December 31, 2014 primarily resulted from our evaluation of a portion of our recently acquired Southwest Appalachia assets. Unevaluated costs excluded from amortization at the end of 2015 included $50 million related to our properties in Canada. The increase in unevaluated costs from December 31, 2013 to December 31, 2014 primarily resulted from the Chesapeake Property Acquisition. See Note 4 to the consolidated financial statements for additional information regarding our unevaluated costs excluded from amortization.

The timing and amount of production and reserve additions could have a material impact on our per unit costs.

Midstream Services

	For the years ended December 31,					
	2015		2014		2013	
	($ in millions, except volumes)					
Marketing revenues	**$**	**2,628**	$	3,797	$	2,830
Gas gathering revenues	**$**	**491**	$	562	$	516
Marketing purchases	**$**	**2,566**	$	3,738	$	2,783
Operating costs and expenses	**$**	**247**	$	260	$	238
Gain on sale of assets, net	**$**	**277**	$	–	$	–
Operating income	**$**	**583**	$	361	$	325
Volumes marketed (Bcfe)		**1,127**		904		786
Volumes gathered (Bcf)		**799**		963		900

Revenues

Revenues from our marketing activities were down 31% to $2.6 billion for 2015 compared to 2014 as a 25% increase in volumes marketed was more than offset by a 45% decrease in the prices received for volumes marketed. Revenues from our marketing activities were up 34% to $3.8 billion for 2014 compared to 2013 primarily due to a 17% increase in the average price received for volumes marketed and a 15% increase in volumes marketed. Of the total natural gas volumes marketed, production from our E&P operated wells accounted for 97% in 2015, 97% in 2014 and 96% in 2013. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in marketing purchase expenses. Our Midstream Services segment marketed approximately 60% of our combined oil and NGL production for the year ended December 31, 2015.

Revenues from our gathering activities were down 13% to $491 million for 2015 compared to 2014, primarily from a 17% decrease in natural gas volumes gathered in 2015. Revenues from our gathering activities were up 9% to $562 million for 2014 compared to 2013, primarily due to a 7% increase in natural gas volumes gathered in 2014. The decrease in gathering revenues for 2015 was primarily due to the divestiture of our northeast Pennsylvania and East Texas gathering assets. The divested gathering assets accounted for $21 million, $67 million and $48 million of our gathering revenues for the years ended December 31, 2015, 2014 and 2013, respectively.

Operating Income

Operating income from our Midstream Services segment increased 61% to $583 million in 2015 and increased 11% to $361 million in 2014. The increase in operating income in 2015 includes a $277 million net gain related to the sale of our northeast Pennsylvania and East Texas gathering assets. Excluding this gain, operating income decreased 15% to $306 million in 2015 primarily due to a decrease in volumes gathered resulting from lower production volumes in the Fayetteville Shale and the sale of our northeast Pennsylvania and East Texas gathering assets. A decrease of $71 million in natural gas gathering revenues was only slightly offset by a $13 million decrease in operating costs and expenses, exclusive of marketing purchases, and a $3 million increase in the margin generated by our marketing activities. The increase in operating income for 2014 compared to 2013 was due to a $46 million increase in gathering revenues and an increase of $12 million in the margin generated from our natural gas marketing activities, partially offset by a $22 million increase in operating costs and expenses, exclusive of purchased natural gas costs, associated with the increase in natural gas volumes gathered. The divested gathering assets accounted for $13 million, $35 million and $23 million of our operating income for the years ended December 31, 2015, 2014 and 2013, respectively.

The margin generated from marketing activities was $62 million for 2015, compared to $59 million for 2014 and $47 million for 2013. Margins are driven primarily by volumes marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increases in margins generated are primarily the result of a 25% increase in volumes marketed in 2015 and a 15% increase in volumes marketed in 2014, as compared to prior years, resulting from the marketing of our increased E&P production volumes. We enter into hedging activities 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 5 to the consolidated financial statements.

Interest Expense

Interest expense, net of capitalization, was $56 million in 2015, a decrease of $3 million compared to 2014, as an increase in gross interest expense was more than offset by an increase in our interest capitalized. Gross interest expense increased to $260 million in 2015 from $114 million in 2014 due to our increased borrowing level related to financing the acquisition of our Southwest Appalachia assets and a $47 million charge for unamortized fees associated with the repayment of our bridge facility in January 2015. Interest capitalized increased to $204 million in 2015, compared to $55 million in 2014 as the result of the increase in our unevaluated property balance associated with the 2014 acquisition of our Southwest Appalachia assets.

Interest expense, net of capitalization, was $59 million in 2014. The increase of $17 million compared to 2013 is primarily due to our increased borrowing level. Interest capitalized was $55 million in 2014 as compared to $62 million in 2013.

Gain (Loss) on Derivatives

In general, our basis swaps, certain fixed price swaps, fixed price call options and interest rate swaps are not designated for hedge accounting treatment. Changes in the fair value of derivatives that are not designated as cash flow hedges are recorded in gain (loss) on derivatives. For those instruments not designated for hedge accounting, we recorded a gain of $44 million related to fixed price swaps, a gain of $13 million related to fixed price call options, a loss of $4 million related to basis swaps and a loss of $6 million related to interest rate swaps for the year ended December 31, 2015.

Income Taxes

Our effective tax rate was 31%, 36%, and 41%, in 2015, 2014 and 2013, respectively. Our effective tax rate decreased in 2015 as compared to 2014 primarily due to an increase in our deferred tax asset valuation allowance. Our effective tax rate decreased in 2014 as compared to 2013 primarily due to a redetermination of the deferred state tax liability to reflect updated state apportionment factors in certain states. In general, differences between our effective tax rate and the federal tax rate of 35% primarily result from the effect of certain state income taxes and permanent items attributable to book-tax differences. We refer you to Note 10 to the consolidated financial statements for additional discussion about our income taxes.

Reconciliation of Non-GAAP Measures

We report our financial results in accordance with GAAP. However, management believes certain non-GAAP performance measures may provide users of this financial information additional meaningful comparisons between current results and the results of our peers and of prior periods.

We define Adjusted EBITDA as net income plus interest, taxes, depreciation, depletion and amortization and any non-cash impairment of natural gas and oil properties, (gain) loss on derivatives, excluding derivatives, settled, gain on sale of assets and certain one-time charges. Management presents measures such as Adjusted EBITDA because it is used by many investors and it is a financial measure commonly used in the energy industry. Adjusted EBITDA should not be considered in isolation or as a substitute for net income, net cash provided by operating activities or other income or cash flow data prepared in accordance with GAAP, or as a measure of the company's profitability or liquidity. Adjusted EBITDA as defined above may not be comparable to similarly titled measures of other companies. The table below reconciles Adjusted EBITDA, as defined, with net income.

	E&P	Midstream Services	Other	Total
2015		(in millions)		
Net income (loss) attributable to common stock	$ (4,848)	$ 297	$ (111)	$ **(4,662)**
Mandatory convertible preferred stock dividend	–	–	106	**106**
Net income (loss)	$ (4,848)	$ 297	$ (5)	$ **(4,556)**
Add back (deduct):				
Depreciation, depletion and amortization expense	1,028	62	1	**1,091**
Impairment of natural gas and oil properties	6,950	–	–	**6,950**
Gain on sale of asset	(6)	(277)	–	**(283)**
Write-down of inventory	23	9	–	**32**
Loss on derivatives excluding derivatives, settled	155	–	–	**155**
Net interest expense	47	9	–	**56**
Provision (benefit) for income taxes	(2,273)	268	–	**(2,005)**
Adjusted EBITDA	$ 1,076	$ 368	$ (4)	$ **1,440**
2014				
Net income (loss)	$ 704	$ 224	$ (4)	$ **924**
Add back (deduct):				
Depreciation, depletion and amortization expense	884	58	–	**942**
(Gain) loss on derivatives excluding derivatives, settled	(131)	1	–	**(130)**
Net interest expense	47	12	–	**59**
Provision for income taxes	402	123	–	**525**
Adjusted EBITDA	$ 1,906	$ 418	$ (4)	$ **2,320**
2013				
Net income (loss)	$ 509	$ 196	$ (1)	$ **704**
Add back (deduct):				
Depreciation, depletion and amortization expense	735	51	1	**787**
Gain on derivatives excluding derivatives, settled	(21)	–	–	**(21)**
Net interest expense	30	11	1	**42**
Provision (benefit) for income taxes	368	119	(1)	**486**
Adjusted EBITDA	$ 1,621	$ 377	$ –	$ **1,998**

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally generated funds, our $2.0 billion revolving credit facility and funds accessed through term loans such as our $750 million term loan facility and capital markets as our primary sources of liquidity.

In 2016, we expect to have decreased activity in the Appalachian Basin and the Fayetteville Shale as a result of the low commodity price environment. Accordingly, we anticipate adjusting our activity levels and are targeting a capital investment program aligned with the cash flow expected to be generated during the year. Although our 2016 capital investment program is expected to be funded through cash flow from operations, we have the financial flexibility to draw on a portion of the funds available under our revolving credit facility to fund the portion of our planned capital investments exceeding our operating cash flow as necessary (discussed below under "Capital Investments"). We refer you to Note 8 of the consolidated financial statements included in this Annual Report and the section below under "Financing Requirements" for additional discussion of our revolving credit facility and commercial paper program.

As of December 31, 2015, our capital structure consisted of 67% debt and 33% equity. We believe that our operating cash flow and available funds under our revolving credit facility will be adequate to meet our capital and operating requirements for 2016. If we do not have adequate liquidity or are unable to obtain financing on favorable terms or at all, however, we may not be able to make intended capital investments, which could restrict our ability to grow and could have a material adverse effect on our results of operations, cash flows and financial condition. Additionally, our ability to make payments on and to refinance our indebtedness will depend on our ability to generate cash in the future. See "Risk Factors – Lower commodity prices may impair our ability to service our existing debt or refinance it when it becomes due." The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the revolving credit facility. Although we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet our obligation. We refer you to the section below under "Financing Requirements" for additional discussion of our compliance with the covenants of our revolving credit and term loan facilities.

Net cash provided by operating activities decreased 32% to $1.6 billion in 2015, due to a decrease in net income adjusted for non-cash expenses and changes in working capital accounts. Net cash provided by operating activities increased 22% to $2.3 billion in 2014 over 2013 due to an increase in net income adjusted for non-cash expenses and changes in working capital accounts. For 2015, requirements for our capital investments were funded primarily from our cash generated by operating activities, net proceeds from borrowings under our revolving credit facility, commercial paper, term loan agreement and cash and cash equivalents. Net cash from operating activities provided 66% of our cash requirements for capital investments, including acquisitions, in 2015, 31% in 2014 and 85% in 2013.

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 5, "Derivatives and Risk Management" in the consolidated financial statements for further details. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete 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.

Additionally, our short-term cash flows are dependent on the timely collection of receivables from our customers and co-owners. 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 co-owners 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 will adjust our discretionary uses of cash dependent upon available cash flow. Further, we may from time to time seek to retire or rearrange some or all of our outstanding debt or preferred stock through cash purchases, retirements, new issuances, privately negotiated transactions, tender offers or otherwise. Such transactions, if any, could be material and will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors.

Capital Investments

Our capital investments were $2.4 billion in 2015 compared to $7.4 billion in 2014 and $2.2 billion in 2013. Capital investments include a decrease of $33 million in 2015, an increase of $155 million in 2014 and a decrease of $25 million in 2013 related to the change in accrued expenditures between years. Our E&P segment investments in 2015 were $2.3 billion, which included $533 million, in total, relating to the acquisitions from WPX Energy, Inc. ("WPX") and Statoil ASA ("Statoil"), compared to $7.3 billion in 2014, which included $5.2 billion primarily related to the Chesapeake Property Acquisition, and $2.1 billion in 2013, which included $96 million primarily related to the acquisition of properties in Northeast Appalachia. Our Midstream Services capital investments for 2015 included $109 million related to the acquisition from WPX.

	Capital investments for the years ended December 31,		
	2015	2014	2013
		(in millions)	
Exploration and production	**$ 1,725**	$ 2,021	$ 1,956
Acquisitions	**642**	5,233	96
Midstream Services	**58**	144	158
Other	**12**	49	25
	$ 2,437	$ 7,447	$ 2,235

In 2016, we expect to have decreased activity in the Appalachian Basin and the Fayetteville Shale as a result of the lower commodity price environment. We anticipate adjusting our activity levels throughout our portfolio and are targeting a capital investment program aligned with the cash flow expected to be generated during the year. Although our 2016 capital investment program is expected to be funded through cash flow from operations, we have the financial flexibility to utilize borrowings under our revolving credit facility and our commercial paper program as necessary.

Financing Requirements

Our total debt outstanding was $4.7 billion as of December 31, 2015, compared to $7.0 billion at December 31, 2014.

In November 2015, we entered into a $750 million unsecured three-year term loan credit agreement with various lenders that was used to repay borrowings under the revolving credit facility. The interest rate on the term loan facility is determined based upon our public debt ratings from S&P and Moody's and was 137.5 basis points over the London Interbank Offered Rate ("LIBOR") as of December 31, 2015. In February 2016, S&P and Moody's downgraded our ratings to BB+ and B1, respectively, increasing our interest rate on the term loan to 162.5 basis points over LIBOR. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business.

In April 2015, we entered into a commercial paper program which allowed us to issue up to $2.0 billion in commercial paper, provided that outstanding borrowings from our commercial paper program, combined with outstanding borrowings under our revolving credit facility, not exceed $2.0 billion. The commercial paper issuance had terms of up to 397 days and carried interest at rates agreed upon at the time of each issuance. As of December 31, 2015, we had no outstanding issuances under our commercial paper program and have no plans of utilizing the commercial paper market after the first quarter of 2016.

In January 2015, we completed concurrent underwritten public offerings of 30,000,000 shares of 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). Net proceeds from the offerings totaled approximately $2.3 billion, after underwriting discount and expenses. Each depositary share represents a 1/20th interest in a share of our 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 a $4.5 billion 364-day bridge facility that we entered into in December 2014 in connection with our acquisition of assets in Southwest Appalachia, with the remaining balance fully repaid with proceeds from our January 2015 public offering of $2.2 billion in senior notes.

The mandatory convertible preferred stock entitles the holders to a proportional fractional interest in the rights and preferences of the convertible preferred stock, including conversion, dividend, liquidation and voting rights. Dividends are to be paid at a rate of 6.25% per annum on the liquidation preference of $1,000 per share and can be paid in cash, common stock or a combination of both. Unless converted earlier at the option of the holders, on or around January 15, 2018 each share of convertible preferred stock will automatically convert into between 37.0028 and 43.4782 shares of our common stock (and, correspondingly, each depositary share will convert into between 1.85014 and 2.17391 shares of our common stock), subject to customary anti-dilution adjustments, depending on the volume-weighted average price of our common stock over a 20 trading-day period immediately prior to that date.

Our mandatory convertible preferred stock has 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. As such, it is 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.

In January 2015, we completed a public offering of $350 million aggregate principal amount of our 3.30% senior notes due 2018 (the “2018 Notes”), $850 million aggregate principal amount of our 4.05% senior notes due 2020 (the “2020 Notes”) and $1.0 billion aggregate principal amount of our 4.95% senior notes due 2025 (the “2025 Notes” and 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 proceeds from the sale of the Notes were used to repay all principal and interest remaining outstanding under our $4.5 billion 364-day bridge facility, which was first reduced with proceeds from our concurrent underwritten public offerings of common stock and depositary shares. Proceeds from the sale of the Notes were also used to repay a portion of amounts outstanding under our revolving credit facility. The Notes were sold to the public at a price of 99.949% of their face value for the 2018 Notes, 99.897% of their face value for the 2020 Notes and 99.782% of their face value for the 2025 Notes. The interest rates on the Notes is determined based upon our public debt ratings from S&P and Moody’s. Downgrades from either rating agency increase our interest costs by 25.0 basis points per downgrade level on the following semi-annual bond interest payment. Based on the February 2016 downgrades from S&P and Moody’s our interest rates on these notes will increase by 125.0 basis points effective July 2016.

In December 2014, we entered into a $500 million unsecured two-year term loan credit agreement with various lenders. The term loan facility required prepayments under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business or for specified uses and was repaid in full in April 2015 principally with proceeds from the divestiture of our northeast Pennsylvania gathering assets and borrowings under our revolving credit facility.

In December 2013, we entered into a credit agreement that exchanged our previous revolving credit facility. Under the revolving credit and facility, we have a borrowing capacity of $2.0 billion. Our current revolving credit facility has a maturity date of December 2018 and options for two one-year extensions with participating lender approval. The amount available under the revolving credit facility may be increased by $500 million upon our agreement with our participating lenders. The interest rate on the revolving credit facility is determined based upon our public debt ratings from S&P and Moody’s and was 150.0 basis points over LIBOR as of December 31, 2015. Based on the February 2016 downgrades from S&P and Moody’s our interest rate increased to 200.0 basis points over LIBOR. The revolving credit facility is unsecured and is not guaranteed by any of our subsidiaries. Contemporaneously with the execution of the credit agreement, in December 2013, we obtained releases of subsidiary guarantees under the 7.15%, 7.5%, 7.35%, 7.125% and 4.10% senior notes.

Our revolving credit and term loan facilities contain covenants that impose certain restrictions on us. Under our revolving credit and term loan facilities 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 any full cost ceiling impairments, certain non-cash hedging activities and our pension and other postretirement liabilities. Therefore, under our revolving credit and term loan facilities, our adjusted capital structure as of December 31, 2015 was 38% debt and 62% equity. We were in compliance with all of the covenants of our revolving credit and term loan facilities as of December 31, 2015. Although we do not anticipate any violations of our financial covenants, our ability to comply with these covenants are 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 oil. If we are unable to borrow under our revolving credit facility, we may have to decrease our capital investment plans.

Our hedges allow us to ensure a certain level of cash flow to fund our operations. At February 23, 2016, we had NYMEX commodity price hedges in place on 37 Bcf of our targeted 2016 natural gas production. The amount of long-term debt we incur will be largely dependent upon commodity prices and our capital investment plans.

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, 2015, our material off-balance sheet arrangements and transactions include operating lease arrangements. 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.

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, 2015, were as follows:

Contractual Obligations:

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
			(in millions)		
Transportation charges[1]	**$ 8,881**	$ 623	$ 1,403	$ 1,453	$ 5,402
Debt	**4,733**	1	1,882	850	2,000
Interest on debt[2]	**1,091**	202	372	233	284
Operating leases[3]	**275**	71	108	68	28
Compression services[4]	**49**	21	22	6	–
Operating agreements	**10**	10	–	–	–
Purchase obligations	**2**	2	–	–	–
Other obligations[5]	**602**	31	35	14	522
	$ 15,643	$ 961	$ 3,822	$ 2,624	$ 8,236

(1) As of December 31, 2015, we had commitments for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems. Of the total $8.9 billion, 38% related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. Additionally, $100 million relates to demand charges under firm transportation agreements under which we have the option to reduce our commitment by 531 Bcf beginning in 2018.

(2) Interest payments on our senior notes were calculated utilizing the fixed rates associated with our fixed rate notes outstanding at December 31, 2015. Interest payments on the revolving credit facility were calculated by assuming that the December 31, 2015 outstanding balance of $116 million will be outstanding through the December 2018 maturity date. Interest payments on the term loan facility were calculated by assuming that the December 31, 2015 outstanding balance of $750 million will be outstanding through the December 2018 maturity date. A constant rate of 1.886% and 1.775%, the rate as of December 31, 2015, was assumed for the revolving credit facility and term loan facility, respectively. All interest rates were based on our credit ratings as of December 31, 2015.

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

(4) As of December 31, 2015, our Midstream Services segment had commitments of approximately $42 million and our E&P segment had commitments of approximately $7 million for compression services associated primarily with our Fayetteville and Southwest Appalachia divisions.

(5) Our other significant contractual obligations include approximately $572 million for asset retirement obligations primarily relating to natural gas and oil properties and 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 12 to the consolidated financial statements and "Critical Accounting Policies and Estimates" below for additional information.

We refer you to Note 8 to the consolidated financial statements for a discussion of the terms of our debt.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our revolving credit facility described in "Financing Requirements" above. We had negative working capital of $0.3 billion as of December 31, 2015 and negative working capital of $4.3 billion at December 31, 2014. The negative working capital as of December 31, 2015 was primarily due to a decrease in derivative assets in 2015. The negative working capital as of December 31, 2014 was driven by the outstanding balance on our bridge facility, which was repaid in full in January 2015.

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.

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. In the second and third quarters of 2015, 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, respectively, and resulted in non-cash ceiling test impairments. 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. At December 31, 2014, 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 of $4.35 per MMBtu for Henry Hub natural gas, West Texas Intermediate oil of $91.48 per barrel, and NGLs of $23.79 per barrel. At December 31, 2013, 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 $3.67 per MMBtu, for West Texas Intermediate oil of $93.42 and for NGLs of $43.45 per barrel. Current 2016 forward pricing will likely result in additional impairments to our natural gas and oil properties in the first quarter of 2016 ranging from approximately $300 million to $500 million, net of tax, when excluding future changes in costs excluded from amortization, with likely material impairments continuing beyond the first quarter.

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. Our reserve base as of December 31, 2015 is approximately 95% natural gas compared to 91% as of December 31, 2014. In the past, nearly all of our reserve base has been 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 standardized measure and reserve quantities as of December 31, 2015, were $2.4 billion and 6.2 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 29 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, Whites Stone

Energy and H.J. Gruy & Associates, 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 Vice President and General Manager – Strategy, Performance and Innovation who has more than 29 years of experience in reservoir engineering including the estimation of natural gas, oil and NGL reserves in multiple basins in the United States. Prior to joining Southwestern in 1993, our Vice President and General Manager – Strategy, Performance and Innovation served in various engineering roles for Conoco Inc and is a member of the Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers, American Institute of Professional Geologists, IPAA and TIPRO. He is also a Licensed Professional Engineer in the state of Texas. On our behalf, the Vice President and General Manager – Strategy, Performance and Innovation engages 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 33 years and over 13 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 23 years and over 13 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 93% of our total reserve base as of December 31, 2015. 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 100% 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 properties in the bottom 20% of the total present worth are typically not reviewed in the audit. The fields included in approximately the top 100% present value as of December 31, 2015, 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 January 15, 2016, NSAI issued its audit opinion as to the reasonableness of our reserve estimates for the year-ended December 31, 2015, 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.

Business Combinations

We account for business combinations under the acquisition method of accounting. Accordingly, we recognize amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of proved and unproved natural gas and oil properties. The fair values of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of reserves, future operating and development costs, future commodity prices and a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of oil and natural gas properties within the same regions, and use that data as a proxy for fair market value; for example, the amount a willing buyer and seller would enter into in exchange for such properties. Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill. Any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain on bargain purchase. Deferred taxes are recorded for any differences between the assigned values and the tax basis of assets and liabilities.

In January 2015, we completed acquisitions of certain natural gas and oil assets from WPX Energy, Inc. (the "WPX Property Acquisition") and Statoil ASA (the "Statoil Property Acquisition"). These acquisitions qualified as business combinations and as such, we estimated the fair value of the assets acquired and liabilities assumed as of the January 2015 acquisition dates. 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. We used discounted cash flow models and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas 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 7 of our consolidated financial statements. We recorded the assets acquired and liabilities assumed in the WPX Property Acquisition and the Statoil Property Acquisition at their estimated fair values of approximately $270 million and $357 million, respectively, which we consider to be representative of the prices paid by typical market participants. These measurements resulted in no goodwill or bargain purchases being recognized.

The 2014 Chesapeake Property Acquisition qualified as a business combination, and as such, we estimated the fair value of the assets acquired and liabilities assumed as of the December 22, 2014 acquisition date. We recorded the assets acquired and liabilities assumed in the Chesapeake Property Acquisition at their estimated fair value of approximately $5.0 billion, which we consider to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized.

Hedging

We use natural gas agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas. 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 2015, 2014, and 2013 we hedged 27%, 60% and 44% of our natural gas production, respectively. 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 hedged.

Our derivative instruments are recorded at fair value in our consolidated financial statements and generally qualify for hedge accounting. We have established the fair value of derivative instruments using data provided by our counterparties in conjunction with assumptions evaluated internally using established index prices and other sources. These valuations are recognized as assets or liabilities on our balance sheet and, to the extent an open position is an effective cash flow hedge on equity production, the offset is recorded in other comprehensive income. Results of settled commodity derivative transactions that qualify for hedge accounting are reflected in gas sales. Any derivative not designated for hedge accounting treatment or any ineffective portion of a properly designated hedge is recognized immediately in earnings. As of December 31, 2015, our fixed price basis swaps and fixed price call options were not designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated as cash flow hedges are recorded in gain (loss) on derivatives. For the year ended December 31, 2015, we recorded a gain on derivatives of $44 million related to fixed price swaps not designated for hedge accounting, a gain on derivatives of $13 million related to fixed price call options that were not designated for hedge accounting treatment and a loss on derivatives of $4 million related to the basis swaps that were not designated for hedge account treatment. Also recorded in gain (loss) on derivatives at December 31, 2015 was a loss of $6 million related to our interest rate swap.

Future market price volatility could create significant changes to the hedge 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 12 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, 2015 benefit obligation and periodic benefit cost to be recorded in 2016, the discount rate assumed is 4.60% and 4.25%, respectively. This compares to a discount rate of 4.25% and 5.00% for the benefit obligation and periodic benefit cost recorded in 2015, respectively. For the 2016 periodic benefit cost, the expected return assumed is 7.00%, compared to an expected return of 7.00% in 2015.

Using the assumed rates discussed above, we recorded total benefit cost of $19 million in 2015 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 50 basis point change in those assumptions would have had on our 2015 pension expense:

	Increase (Decrease) of Annual Pension Expense	
	50 Basis Point Increase	50 Basis Point Decrease
	(in millions)	
Discount rate	$ (1)	$ 1
Expected long-term rate of return	$ (1)	$ 1

As of December 31, 2015, we recognized a liability of $50 million, compared to $44 million at December 31, 2014, related to our pension and other postretirement benefit plans. During 2015, we also made cash payments totaling $12 million to fund our pension and other postretirement benefit plans.

Asset Retirement Obligations

We own natural gas and oil properties, which require expenditures to plug and abandon the wells when reserves in the wells are depleted. 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 rate, 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 Implemented in this Report

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 implemented.

New Accounting Standards Not Yet Implemented in this Report

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 not yet implemented.

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 and Section 21E of the Exchange Act. 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 based on reasonable assumptions, such 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;
* difficulties in integrating our operations as a result of any significant acquisitions;
* our ability to transport our production to the most favorable markets or at all;
* 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 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 subject to the approval of our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist 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. No single purchaser accounted for greater than 10% of revenues as of December 31, 2015. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

The following table presents the principal cash payments for our debt obligations and related weighted-average interest rates by expected maturity dates as of December 31, 2015. As of December 31, 2015, we had $3,867 million of outstanding senior notes with a weighted average interest rate of 4.82%, $750 million of term loan facility debt with a variable interest rate of 1.775%, $116 million of borrowings under our revolving credit facility with a variable interest rate of 1.886% and no outstanding balance on our commercial paper program. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates.

	Expected Maturity Date							Fair Value
	2016	2017	2018	2019	2020	Thereafter	Total	12/31/15
	(in millions)							
Fixed Rate Payments	$ 1	$ 41	$ 975	$ –	$ 850	$ 2,000	$ 3,867	$ 2,672
Weighted Average Interest Rate	7.15 %	7.21 %	5.98 %	– %	4.05 %	4.53 %	4.82 %	– %
Variable Rate Payments	–	–	866	–	–	–	866	866
Weighted Average Interest Rate	– %	– %	1.79 %	– %	– %	– %	1.79 %	– %

Commodities Risk

We use over-the-counter fixed price swap agreements and fixed price options to hedge 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 hedged. 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.

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for natural gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates. At December 31, 2015, the net fair value of our financial instruments related to natural gas production was a $3 million asset.

	Volume (Bcf)	Weighted Average Price to be Swapped ($/MMBtu)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Weighted Average Basis Differential ($/MMBtu)	Fair value at December 31, 2015 ($ in millions)
Natural Gas (Bcf):						
Basis Swaps:						
2016	5	$ –	$ –	$ –	$ 0.75	$ 3
Fixed Price Call Options:						
2016	120	$ –	$ 5.00	$ –	$ –	$ –

As of December 31, 2015, our basis swaps, certain fixed price swaps, fixed price call options, and interest rate swap were not designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated as cash flow hedges are recorded in gain (loss) on derivatives. For the year ended December 31, 2015, we recorded a loss on derivatives excluding derivatives, settled of $164 million related to fixed price swaps not designated for hedge accounting, a gain on derivatives excluding derivatives, settled of $13 million related to fixed price call options not designated for hedge accounting, a loss on derivatives excluding derivatives, settled of $2 million related to basis swaps not designated for hedge accounting, and a loss on derivatives excluding derivatives, settled of $2 million related to our interest rate swap not designated for hedge accounting.

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

	Page
Management's Report on Internal Control Over Financial Reporting	64
Report of Independent Registered Public Accounting Firm	65
Consolidated Statements of Operations for the years ended December 31, 2015, 2014 and 2013	66
Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2015, 2014 and 2013	67
Consolidated Balance Sheets as of December 31, 2015 and 2014	68
Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013	69
Consolidated Statements of Equity for the fiscal years ended December 31, 2015, 2014 and 2013	70
Notes to Consolidated Financial Statements, December 31, 2015, 2014 and 2013	71

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, 2015, utilizing the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control—Integrated Framework (2013)*.

Based on this evaluation, management concluded the Company's internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Southwestern Energy Company and its subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 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, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (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
February 25, 2016

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the years ended December 31,		
	2015	2014	2013
	(in millions, except share/per share amounts)		
Operating Revenues:			
Gas sales	**$ 1,946**	$ 2,827	$ 2,381
Oil sales	**76**	19	14
NGL sales	**73**	3	2
Marketing	**863**	996	792
Gas gathering	**175**	193	182
	3,133	4,038	3,371
Operating Costs and Expenses:			
Marketing purchases	**852**	980	782
Operating expenses	**689**	427	328
General and administrative expenses	**246**	221	191
Depreciation, depletion and amortization	**1,091**	942	787
Impairment of natural gas and oil properties	**6,950**	–	–
Gain on sale of assets, net	**(283)**	–	–
Taxes, other than income taxes	**110**	95	79
	9,655	2,665	2,167
Operating Income (Loss)	**(6,522)**	1,373	1,204
Interest Expense:			
Interest on debt	**200**	101	100
Other interest charges	**60**	13	4
Interest capitalized	**(204)**	(55)	(62)
	56	59	42
Other Income (Loss), Net	**(30)**	(4)	2
Gain on Derivatives	**47**	139	26
Income (Loss) Before Income Taxes	**(6,561)**	1,449	1,190
Provision (Benefit) for Income Taxes:			
Current	**(2)**	21	(11)
Deferred	**(2,003)**	504	497
	(2,005)	525	486
Net Income (Loss)	**$ (4,556)**	$ 924	$ 704
Mandatory convertible preferred stock dividend	**106**	–	–
Net Income (Loss) Attributable to Common Stock	**$ (4,662)**	$ 924	$ 704
Earnings (Loss) Per Common Share:			
Basic	**$ (12.25)**	$ 2.63	$ 2.01
Diluted	**$ (12.25)**	$ 2.62	$ 2.00
Weighted Average Common Shares Outstanding:			
Basic	**380,521,039**	351,446,747	350,465,430
Diluted	**380,521,039**	352,410,683	351,101,452

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,		
	2015	2014	2013
		(in millions)	
Net income (loss)	$ **(4,556)**	$ 924	$ 704
Change in derivatives:			
Settlements [(1)]	**(128)**	16	(185)
Ineffectiveness [(2)]	**1**	–	1
Change in fair value of derivative instruments [(3)]	**29**	73	22
Total change in derivatives	**(98)**	89	(162)
Change in value of pension and other postretirement liabilities:			
Current period net gain (loss) [(4)]	**(3)**	(15)	11
Amortization of prior service cost and net loss included in net periodic pension cost [(5)]	**2**	–	1
Total change in value of pension and other postretirement liabilities	**(1)**	(15)	12
Change in currency translation adjustment	**(11)**	(8)	(4)
Comprehensive income (loss)	$ **(4,666)**	$ 990	$ 550

(1) Net of ($81), $10, and ($124) million in taxes for the years ended December 31, 2015, 2014 and 2013, respectively.

(2) Net of $0, $0, and $1 million in taxes for the years ended December 31, 2015, 2014 and 2013, respectively.

(3) Net of $16, $49, and $16 million in taxes for the years ended December 31, 2015, 2014 and 2013, respectively.

(4) Net of $0, ($10), and $8 million in taxes for the years ended December 31, 2015, 2014 and 2013, respectively.

(5) Net of $0, $0, and $1 million in taxes for the years ended December 31, 2015, 2014, and 2013, respectively.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

		December 31, 2015		December 31, 2014
ASSETS		(in millions)		
Current assets:				
Cash and cash equivalents	**$**	**15**	$	53
Accounts receivable, net		**327**		530
Inventories		**3**		37
Derivative assets		**3**		337
Other current assets		**45**		158
Total current assets		**393**		1,115
Natural gas and oil properties, using the full cost method, including $3,727 million in 2015 and $4,646 million in 2014 excluded from amortization		**22,478**		20,506
Gathering systems		**1,280**		1,439
Other		**606**		612
Less: Accumulated depreciation, depletion and amortization		**(16,821)**		(8,845)
Total property and equipment, net		**7,543**		13,712
Other long-term assets		**174**		98
TOTAL ASSETS	**$**	**8,110**	$	14,925
LIABILITIES AND EQUITY				
Current liabilities:				
Short-term debt	**$**	**1**	$	4,501
Accounts payable		**513**		653
Taxes payable		**64**		92
Interest payable		**75**		34
Current deferred income taxes		**–**		109
Dividends payable		**27**		–
Derivative liabilities		**3**		9
Other current liabilities		**24**		30
Total current liabilities		**707**		5,428
Long-term debt		**4,728**		2,466
Deferred income taxes		**–**		1,951
Pension and other postretirement liabilities		**50**		44
Other long-term liabilities		**343**		374
Total long-term liabilities		**5,121**		4,835
Commitments and contingencies (see Note 9)				
Equity:				
Common stock, $0.01 par value; 1,250,000,000 shares authorized; issued 390,138,549 shares in 2015 and 354,488,992 in 2014		**4**		4
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 6.25% Series B Mandatory Convertible, $1,000 per share liquidation preference, 1,725,000 shares issued and outstanding as of December 31, 2015		–		–
Additional paid-in capital		**3,409**		1,019
Retained earnings (Accumulated deficit)		**(1,082)**		3,577
Accumulated other comprehensive income (loss)		**(48)**		62
Common stock in treasury, 47,149 and 11,055 shares as of December 31, 2015 and 2014, respectively		**(1)**		–
Total equity		**2,282**		4,662
TOTAL LIABILITIES AND EQUITY	**$**	**8,110**	$	14,925

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,		
	2015	2014	2013
		(in millions)	
Cash Flows From Operating Activities			
Net income (loss)	$ **(4,556)**	$ 924	$ 704
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**1,092**	942	787
Impairment of natural gas and oil properties	**6,950**	–	–
Amortization of debt issuance cost	**53**	10	4
Deferred income taxes	**(2,003)**	504	497
(Gain) loss on derivatives, net of settlement	**155**	(130)	(21)
Stock-based compensation	**26**	18	13
Gain on sale of assets, net	**(283)**	–	–
Other	**34**	2	1
Change in assets and liabilities:			
Accounts receivable	**203**	(66)	(86)
Inventories	**4**	1	(6)
Accounts payable	**(78)**	84	74
Taxes payable	**(28)**	24	5
Interest payable	**9**	–	(1)
Advances from partners	**–**	–	(69)
Other assets and liabilities	**2**	22	7
Net cash provided by operating activities	**1,580**	2,335	1,909
Cash Flows From Investing Activities			
Capital investments	**(1,798)**	(2,043)	(2,157)
Acquisitions	**(579)**	(5,298)	(96)
Proceeds from sale of property and equipment	**729**	43	18
Transfers to restricted cash	**–**	–	9
Other	**10**	10	10
Net cash used in investing activities	**(1,638)**	(7,288)	(2,216)
Cash Flows From Financing Activities			
Payments on current portion of long-term debt	**(1)**	(1)	(1)
Payments on long-term debt	**(500)**	–	–
Payments on short-term debt	**(4,500)**	–	–
Payments on revolving credit facility	**(3,024)**	(5,179)	(3,148)
Borrowings under revolving credit facility	**2,840**	5,196	3,430
Payments on commercial paper	**(7,988)**	–	–
Borrowings under commercial paper	**7,988**	–	–
Change in bank drafts outstanding	**12**	11	(7)
Proceeds from issuance of long-term debt	**2,950**	500	–
Proceeds from issuance of short-term debt	**–**	4,500	–
Debt issuance costs	**(20)**	(56)	–
Proceeds from exercise of common stock options	**–**	12	10
Proceeds from issuance of common stock	**669**	–	–
Proceeds from issuance of mandatory convertible preferred stock	**1,673**	–	–
Preferred stock dividend	**(79)**	–	–
Other	**–**	–	(7)
Net cash provided by financing activities	**20**	4,983	277
Effect of exchange rate changes on cash	**–**	–	(1)
Increase (decrease) in cash and cash equivalents	**(38)**	30	(31)
Cash and cash equivalents at beginning of year	**53**	23	54
Cash and cash equivalents at end of year	$ **15**	$ 53	$ 23

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)	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	**Total**
	(in millions, except share amounts)							
Balance at December 31, 2012	351,100,391	$ 4	–	$ 934	$ 1,949	$ 150	$ (1)	$ **3,036**
Comprehensive loss:								
Net income	–	–	–	–	704	–	–	**704**
Other comprehensive loss	–	–	–	–	–	(154)	–	**(154)**
Total comprehensive income	–	–	–	–	–	–	–	**550**
Stock-based compensation	–	–	–	25	–	–	–	**25**
Exercise of stock options	833,132	–	–	10	–	–	–	**10**
Issuance of restricted stock	1,102,926	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(74,083)	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(25,131)	–	–	(1)	–	–	–	**(1)**
Issuance of stock awards	1,349	–	–	–	–	–	–	**–**
Treasury stock – non-qualified plan	–	–	–	1	–	–	1	**2**
Balance at December 31, 2013	352,938,584	$ 4	–	$ 969	$ 2,653	$ (4)	$ –	**$ 3,622**
Comprehensive income:								
Net income	–	–	–	–	924	–	–	**924**
Other comprehensive income	–	–	–	–	–	66	–	**66**
Total comprehensive income	–	–	–	–	–	–	–	**990**
Stock-based compensation	–	–	–	38	–	–	–	**38**
Exercise of stock options	402,190	–	–	12	–	–	–	**12**
Issuance of restricted stock	1,299,367	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(140,703)	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(12,133)	–	–	–	–	–	–	**–**
Issuance of stock awards	1,687	–	–	–	–	–	–	**–**
Balance at December 31, 2014	354,488,992	$ 4	–	$ 1,019	$ 3,577	$ 62	$ –	**$ 4,662**
Comprehensive income:								
Net loss	–	–	–	–	(4,556)	–	–	**(4,556)**
Other comprehensive loss	–	–	–	–	–	(110)	–	**(110)**
Total comprehensive loss	–	–	–	–	–	–	–	**(4,666)**
Stock-based compensation	–	–	–	48	–	–	–	**48**
Preferred stock dividends	–	–	–	–	(106)	–	–	**(106)**
Exercise of stock options	–	–	–	–	–	–	–	**–**
Issuance of restricted stock	5,821,125	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(103,162)	–	–	–	–	–	–	**–**
Issuance of common stock	30,000,000	–	–	669	–	–	–	**669**
Issuance of preferred stock	–	–	1,725,000	1,673	–	–	–	**1,673**
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**

The accompanying notes are an integral part of these 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 and oil exploration, development and production ("E&P"). The Company's current operations are principally focused within the United States on the development of unconventional reservoirs located in Pennsylvania, West Virginia and Arkansas.

The Company's operations in northeast Pennsylvania are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale (herein referred to as "Northeast Appalachia"), its operations in West Virginia are also focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs (herein referred to as "Southwest Appalachia") and its operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. Collectively, the Company's properties located in Pennsylvania and West Virginia are herein referred to as the "Appalachian Basin." The Company also actively seeks to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which it refers to as "New Ventures," and has exploration and production activities ongoing in Colorado and Louisiana, along with other areas in which it is currently exploring for new development opportunities. The Company also has drilling rigs in Pennsylvania, West Virginia and Arkansas, as well as in other operating areas, and provides oilfield products and services, principally serving its exploration and production operations. Southwestern's natural gas gathering and marketing ("Midstream Services") activities primarily support the Company's E&P activities in Arkansas, Pennsylvania, Louisiana and West Virginia.

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 2015 presentation. 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 (discussed in Note 2). 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 year ended December 31, 2015 was insignificant.

Revenue Recognition

Natural gas and liquid sales. Natural gas and liquid 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, 2015 or 2014.

Marketing. The Company generally markets its natural gas and liquids, as well as some products produced by third parties, to brokers, 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.

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.

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 $29 million and $17 million as of December 31, 2015 and 2014, respectively.

Inventory

Inventory is comprised of tubulars and other equipment and natural gas in underground storage. Tubulars and other equipment are carried at the lower of cost or market and are accounted for by a moving weighted average cost method that is applied within specific classes of inventory items. In the fourth quarter of 2015, the Company wrote-down the carrying value of its inventory by $23 million as a result of reduced drilling activity. Natural gas in underground storage is carried at the lower of cost or market and accounted for by a weighted average cost method. During the fourth quarter of 2015, the Company completed the sale of its underground storage facility in Franklin County, Arkansas.

The components of inventory as of December 31, 2015 and December 31, 2014 consisted of the following:

	For years ended December 31,	
	2015	2014
	(in millions)	
Inventory:		
Tubulars and other equipment	**$ 3**	$ 33
Natural gas in underground storage	**–**	4

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, oil and NGL reserves. 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, less accumulated amortization and related deferred income taxes, are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% 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 must 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.

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. No cash flow hedges were in place as of December 31, 2015. In the second and third quarters of 2015, 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, respectively, and resulted in non-cash ceiling test impairments. 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. At December 31, 2014, the ceiling value of the Company's 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 $4.35 per MMBtu, West Texas Intermediate oil of $91.48 per barrel and NGLs of $23.79 per barrel. At December 31, 2013, the ceiling value of the Company's 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 $3.67 per MMBtu, for West Texas Intermediate oil of $93.42 and NGLs of $43.45 per barrel. 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.

Gathering Systems. The Company's investment in gathering systems is primarily related to its Fayetteville Shale assets 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 and actively being evaluated.

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 reserves in the wells are depleted. 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 long-lived assets are 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 weighted average 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 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 can be found in Note 10 – 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 commodity fixed price swaps and fixed price option contracts to hedge sales of natural gas. Gains and losses resulting from the settlement of hedge 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 fixed price swaps 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 fixed price swaps not designated for hedge accounting treatment, interest rate swaps, fixed price call options and basis swaps that were not designated for hedge accounting treatment are recognized in gain (loss) on derivatives in the consolidated statement of operations. See Note 5 – Derivatives and Risk Management and Note 7 – 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 each year. 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 and performance units and the assumed conversion of mandatory convertible preferred stock. 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 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, after underwriting discount and expenses, from the common stock offering were approximately $669 million. Net proceeds, after underwriting discount and expenses, from the depositary share offering were approximately $1.7 billion. Each depositary share represents 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 entitles the holder to a proportional fractional interest in the rights and preferences of the convertible preferred stock, including conversion, dividend, liquidation and voting rights. Unless converted earlier at the option of the holders, on or around January 15, 2018 each share of convertible preferred stock will automatically convert into between 37.0028 and 43.4782 shares of the Company's common stock (and, correspondingly, each depositary share will convert into between 1.85014 and 2.17391 shares of the Company's common stock), subject to customary anti-dilution adjustments, depending on the volume-weighted average price of the Company's common stock over a 20 trading day averaging period immediately prior to that date.

The mandatory convertible preferred stock has 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 is 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.

The following table presents the computation of earnings per share for the years ended December 31, 2015, 2014 and 2013.

	For the years ended December 31,		
	2015	2014	2013
	(in millions, except share/per share amounts)		
Net income (loss)	**$ (4,556)**	$ 924	$ 704
Mandatory convertible preferred stock dividend	**106**	–	–
Net income (loss) attributable to common stock	**$ (4,662)**	$ 924	$ 704
Number of common shares:			
Weighted average outstanding	**380,521,039**	351,446,747	350,465,430
Issued upon assumed exercise of outstanding stock options (1)	**–**	241,603	377,626
Effect of issuance of non-vested restricted common stock (2)	–	448,415	258,396
Effect of issuance of non-vested performance units (3)	–	273,918	–
Effect of issuance of mandatory convertible preferred stock (4)	–	–	–
Weighted average and potential dilutive outstanding	**380,521,039**	352,410,683	351,101,452
Earnings (loss) per common share:			
Basic	**$ (12.25)**	$ 2.63	$ 2.01
Diluted	**$ (12.25)**	$ 2.62	$ 2.00

(1) Due to the net loss for the year ended December 31, 2015, the unvested stock options were not recognized in diluted earnings per share calculations as they would be antidilutive. Options for 3,835,234 shares, 1,446,004 shares and 1,634,695 shares were excluded from the calculation of diluted shares for the years ended December 31, 2015, 2014 and 2013, respectively, because they would have had an antidilutive effect.

(2) Due to the net loss for the year ended December 31, 2015, the unvested share-based payments were not recognized in diluted earnings per share calculations as they would be antidilutive. The calculation excluded 1,990,383 shares, 29,879 shares and 114,433 shares of restricted stock for the years ended December 31, 2015, 2014, and 2013, respectively, because they would have had an antidilutive effect.

(3) Due to the net loss for the year ended December 31, 2015, 140,414 shares of performance units were excluded in the calculation of diluted earnings per share as they would be antidilutive. There were no performance units issued in 2013.

(4) Due to the net loss for the year ended December 31, 2015, the weighted average common shares issuable upon the assumed conversion of the mandatory convertible preferred stock were not recognized in diluted earnings per share calculations as they would be antidilutive. The calculation excluded 70,890,312 weighted average common shares issuable upon the assumed conversion of the mandatory convertible preferred stock because they would have had an antidilutive effect. There were no mandatory convertible preferred shares in 2014 or 2013.

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, 2015, 2014, and 2013.

	For the years ended December 31,		
	2015	2014	2013
		(in millions)	
Cash paid during the year for interest, net of amounts capitalized	**$ 6**	$ 50	$ 36
Cash paid (received) during the year for income taxes	**(6)**	28	19
Increase (decrease) in noncash property additions	**(10)**	174	(13)

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 and are presented as treasury stock and carried at cost. As of December 31, 2015, 47,149 shares were accounted for as treasury stock, compared to 11,055 shares at December 31, 2014.

Foreign Currency Translation

The Company has designated the Canadian dollar as the functional currency for our operations 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 November 2015, the FASB issued Accounting Standards Update No. 2015-17, Balance Sheet Classification of Deferred Taxes (Topic 740) ("Update 2015-17"), which seeks to reduce the complexity in financial reporting. The amendments in Update 2015-17 require that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as non-current on the balance sheet. Although the amendments in Update 2015-17 are effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, the Company has elected to early adopt the amendments of Update 2015-17 on a prospective basis for the current period. The implementation did not have a material impact on the Company's consolidated statement of operations, balance sheet or statement of cash flows. The net deferred tax liability at December 31, 2014 was comprised of net long-term deferred income tax liabilities of $1,951 million, in addition to a net current deferred income tax liability of $109 million.

New Accounting Standards Not Yet Implemented in this Report

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. Topic 606 Revenue from Contracts with Customers will supersede the revenue recognition requirement as in Topic 605 Revenue Recognition. Update 2014-09 requires an entity to recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to those goods or services. Entities may apply the amendments in Update 2014-09 either (a) retrospectively to each reporting period presented, and the entity may elect a practical expedient per the update, or (b) retrospectively with the cumulative effect of initially applying Update 2014-09 recognized at the date of initial application – if an entity elects this transition method it also should provide the additional disclosures in reporting periods. In August 2015, the FASB issued Accounting Standards Update Accounting Standards Update (ASU) No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, which finalizes Proposed ASU No. 2015-240 of the same name, and responds to stakeholders' requests to defer the effective date of the guidance in ASU No. 2014-09. For public entities, Update 2014-09 and Update 2015-14 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The Company is currently evaluating the provisions of Update 2014-09 and 2015-14 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In November 2014, the FASB issued Accounting Standards Update No. 2014-16, Derivatives and Hedging – Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or to Equity (Subtopic 815-15) ("Update 2014-16"), addresses diversity in practice related to the determination of whether derivative features embedded in hybrid instruments issued in the form of a share should be bifurcated and accounted for separately. For public entities, Update 2014-16 is effective for annual reporting periods beginning after December 15, 2015 including interim periods within that reporting period. The Company is currently evaluating the provisions of Update 2014-16 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Interest-Imputation of Interest (Subtopic 835-30) ("Update 2015-03"), which seeks to simplify presentation of debt issuance costs. Update 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this Update. Entities should apply the amendments in Update 2015-03 on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying the new guidance. In August 2015, the FASB issued Accounting Standards Update No. 2015-15, Interest-Imputation of Interest (Subtopic 835-30) ("Update 2015-15"), which addresses the presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements, given the absence of authoritative guidance within Update 2015-03 for debt issuance costs related to line-of-credit arrangements. For public entities, Update 2015-03 and Update 2015-15 are effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period. The Company has evaluated the provisions of Update 2015-03 and Update 2015-15 and expects the impact to be immaterial on its consolidated results of operations, financial position and cash flows.

In May 2015, the FASB issued Accounting Standards Update No. 2015-07, Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (Or Its Equivalent) ("Update 2015-07"), which amends ASC 820, Fair Value Measurement. The standard removes the requirement to categorize within the fair value hierarchy investments for which fair value is measured using the net asset value per share practical expedient and removes certain related disclosure requirements. The amendments in Update 2015-07 are effective for reporting periods beginning after December 15, 2015, with early adoption permitted. The Company is currently evaluating the provisions of Update 2015-07 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In July 2015, the FASB issued Accounting Standards Update No. 2015-11, Inventory (Topic 330) ("Update 2015-11"), which seeks to simplify the measurement of inventory. Update 2015-11 requires that an entity should measure inventory at the lower of cost and net realizable value, where net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. For public entities, the amendments in Update 2015-11 are effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, with early adoption permitted. The Company is currently evaluating the provisions of Update 2015-11 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In July 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-12 ("Update 2015-12"), which consists of three related parts: (1) Plan Accounting: Defined Contribution Pension Plans (Topic 962); Health and Welfare Benefit Plans (Topic 965): Fully Benefit-Responsive Investment Contracts ("Part I"); (2) Plan Accounting: Defined Benefit Pension Plans (Topic 960); Defined Contribution Pension Plans (Topic 962); Health and Welfare Benefit Plans (Topic 965): Plan Investment Disclosures ("Part II"); and (3) Plan Accounting: Defined Benefit Pension Plans (Topic 960); Defined Contribution Pension Plans (Topic 962); Health and Welfare Benefit Plans (Topic 965): Measurement Date Practical Expedient ("Part III"). Part I requires (1) fully benefit-responsive investment contracts to be measured at contract value; and (2) an adjustment to reconcile contract value to fair value, when these measures differ, on the face of the plan financial statements. Part II eliminates the current requirement for both participant-directed investments and non-participant-directed investments to disclose individual investments representing 5% or more of net assets available for benefits, as well as the net appreciation or depreciation for investments by general type on a disaggregated basis. Part III permits plans to measure investments and investment-related accounts as of a month-end date that is closest to the plan's fiscal year-end, when the fiscal period does not coincide with a month-end. The amendments in Update 2015-12 are effective for fiscal years beginning after December 15, 2015, with early adoption permitted. The Company is currently evaluating the provisions of Update 2015-12 and assessing the impact, if any, it may have on its consolidated results of operations, financial position, or cash flows.

In September 2015, the FASB issued Accounting Standards Update No. 2015-16, Business Combinations (Topic 805) ("Update 2015-16"), which seeks to reduce the complexity of amounts recognized in a business combination. The amendments in Update 2015-16 require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments in Update 2015-16 require that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments in Update 2015-16 require an entity to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments in Update 2015-16 are effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. The Company is currently evaluating the provisions of Update 2015-16 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

(2) ACQUISITIONS AND DIVESTITURES

In May 2015, the Company sold conventional oil and gas assets located in East Texas and the Arkoma Basin for approximately $211 million. These properties were previously referred to as the Ark-La-Tex division. The net book value of these assets was primarily in the full cost pool and was held in the E&P segment as of the closing date. The proceeds from the transaction were used to reduce the Company's debt. 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.

In April 2015, the Company sold its gathering assets located in Bradford and Lycoming counties in northeast Pennsylvania to Howard Midstream Energy Partners, LLC 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 is included in gain on sale of assets, net on the consolidated statement of operations. The assets include 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 substantially repay borrowings under the Company's $500 million term loan facility that would have matured in December 2016.

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 transportation is being amortized over 19 years. As of December 31, 2015 the Company has amortized $8.2 million. 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:	
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 in which the Company's subsidiary acquired certain natural gas and oil assets from Statoil ASA covering approximately 30,000 acres in West Virginia and southwest Pennsylvania comprising approximately 20% of Statoil's interests in that acreage for $357 million, (the "Statoil Property Acquisition"). All of these assets are also assets in which the Company has acquired interests under the Chesapeake Property Acquisition. This transaction was funded with the revolving credit facility and was accounted for as a business combination. The Company allocated approximately $357 million of the purchase price to natural gas and oil properties, based on the respective fair values of the assets acquired.

In December 2014, the Company completed an acquisition of certain oil and gas assets from Chesapeake Energy Corporation covering approximately 413,000 net acres in West Virginia and southwest Pennsylvania targeting natural gas, NGLs and crude oil contained in the Upper Devonian, Marcellus and Utica Shales for approximately $5.0 billion. The Chesapeake Property Acquisition was temporarily financed using a $4.5 billion 364-day senior unsecured bridge term loan credit facility and a $500 million two-year unsecured term loan. The Company repaid all principal and interest outstanding on the $4.5 billion bridge facility in January 2015 after permanent financing was finalized and as a result, expensed $47 million of short-term unamortized debt issuance costs related to the bridge facility in January 2015 recognized in other interest charges on the consolidated statement of operations. The term loan facility was repaid in full in April 2015 with proceeds from the divestiture of the Company's northeast Pennsylvania gathering assets and borrowings under the revolving credit facility.

The following table summarizes the consideration paid for the Chesapeake Property Acquisition and the fair value of the assets acquired and liabilities assumed as of the acquisition date, updated for subsequent customary post-closing adjustments:

Consideration:	
Cash	$ 4,949
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Assets acquired:	
Proved natural gas and oil properties	1,418
Unproved natural gas and oil properties	3,573
Other property and equipment	33
Inventory	3
Total assets acquired	5,027
Liabilities assumed:	
Asset retirement obligations	(42)
Other liabilities	(36)
Total liabilities assumed	(78)
	$ 4,949

The above acquisitions qualified as business combinations, and as a result, the Company estimated the fair value 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 a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas 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 7 – Fair Value Measurements.

The Company recorded the assets acquired and liabilities assumed in the Chesapeake Property Acquisition at their estimated fair value of approximately $5.0 billion, which the Company considers to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized. In addition, the Company included $1 million in general and administrative expenses and $5 million in interest expense for fees related to the Chesapeake Property Acquisition on its consolidated statement of operations for the year ended December 31, 2014. The Company included $47 million in other current assets and $1 million in other assets for unamortized fees related to the bridge facility and term loan facility, respectively, for the Chesapeake Property Acquisition on its consolidated balance sheet as of December 31, 2014. In January 2015, the Company repaid in full amounts outstanding on its bridge facility. Therefore, the Company expensed the $47 million of short-term unamortized debt issuance costs associated with the bridge facility in January 2015. The term loan facility was repaid in full in April 2015.

The results of operations of the Chesapeake Property Acquisition have been included in the Company's consolidated financial statements since the December 22, 2014 closing date, including approximately $10 million of total revenue and $2 million of operating income for the year ended December 31, 2014. Summarized below are the consolidated results of operations for the years ended December 31, 2014 and 2013, on an unaudited pro forma basis, as if the acquisition and related financing had occurred on January 1, 2013. The unaudited pro forma financial information was derived from the historical consolidated statement of operations of the Company and the statement of revenues and direct operating expenses for the Chesapeake Property Acquisition properties. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the acquisition and related financing occurred on the basis assumed above, nor is such information indicative of the Company's expected future results of operations. The unaudited pro forma financial information excludes the WPX Property and Statoil Property Acquisitions as the impacts are immaterial.

	For the years ended December 31,	
	2014	2013
	(in millions) (unaudited)	
Revenues	$ 4,439	$ 3,713
Net income attributable to common stock	803	594
Earnings per share		
Basic	$ 2.11	$ 1.56
Diluted	2.10	1.56

In March 2014 and July 2014, the Company entered into several agreements to purchase approximately 380,000 net acres in northwest Colorado principally in the Niobrara formation for approximately $215 million. The Company utilized its revolving credit facility to finance these acquisitions. The Company closed the acquisitions in the second and third quarters in 2014 and accounted for them as asset acquisitions.

In April 2013, the Company entered into a definitive purchase agreement to acquire natural gas properties located in Pennsylvania prospective for the Marcellus Shale for approximately $82 million, subject to closing conditions. The Company utilized its revolving credit facility to finance the acquisition. The Company closed the acquisition during the second quarter of 2013 and accounted for it as an asset acquisition.

(3) PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of December 31, 2015 and December 31, 2014 consisted of the following:

	2015	2014
	(in millions)	
Prepaid taxes	**$ 26**	$ 30
Prepaid insurance	**6**	8
Other prepaid expenses	**11**	5
Deposits (1)	**–**	65
Total	**$ 43**	$ 108

(1) Deposits as of December 31, 2014 consisted of a $50 million and $15 million pre-payment related to the Statoil Property Acquisition and WPX Property Acquisition, respectively.

(4) NATURAL GAS AND OIL PRODUCING ACTIVITIES (UNAUDITED)

The Company's natural gas and oil properties are located in the United States and Canada.

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, 2015 and 2014:

	2015	2014
	(in millions)	
Proved properties	**$ 18,751**	$ 15,860
Unproved properties (1)	**3,727**	4,646
Total capitalized costs	**22,478**	20,506
Less: Accumulated depreciation, depletion and amortization	**(16,248)**	(8,327)
Net capitalized costs	**$ 6,230**	$ 12,179

(1) Includes $50 million and $76 million related to the Company's exploration program in Canada as of December 31, 2015 and 2014, respectively.

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, 2015.

	2015	2014	2013	Prior	**Total**
			(in millions)		
Property acquisition costs (1)	$ 274	$ 2,870	$ 42	$ 105	**$ 3,291**
Exploration and development costs (1)	128	56	29	36	**249**
Capitalized interest (1)	120	22	11	34	**187**
	$ 522	$ 2,948	$ 82	$ 175	**$ 3,727**

(1) Property acquisition costs include $16 million, exploration costs include $26 million and capitalized interest includes $8 million related to the Company's exploration program in Canada.

Of the total net unevaluated costs excluded from amortization as of December 31, 2015, approximately $2.9 billion is related to the Chesapeake Property Acquisition, approximately $265 million is related to the acquisition of undeveloped properties in the Company's New Ventures, excluding its exploration program in Canada, and approximately $121 million is related to the acquisition of the Company's undeveloped properties in the Marcellus Shale. The Company has $50 million of unevaluated costs related to its exploration program in Canada. Additionally, the Company has approximately $157 million of unevaluated costs related to costs of 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:

	2015	2014	2013
		(in millions, except per Mcfe amounts)	
Proved property acquisition costs	**$ 81**	$ 1,455	$ 1
Unproved property acquisition costs [(1)]	**692**	3,934	168
Exploration costs [(2)]	**50**	232	192
Development costs	**1,417**	1,600	1,662
Capitalized costs incurred	**2,240**	7,221	2,023
Full cost pool amortization per Mcfe	**$ 1.00**	$ 1.10	$ 1.08

(1) Included $1 million and $17 million in 2014 and 2013, respectively, related to the Company's exploration program in Canada.
(2) Included $3 million and $12 million in 2014 and 2013, respectively, related to the Company's exploration program in Canada.

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $204 million, $55 million and $62 million during 2015, 2014 and 2013, 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 $307 million, $320 million and $264 million during 2015, 2014 and 2013, respectively, which were directly related to the acquisition, exploration and development of the Company's natural gas and oil properties. Included in these amounts are internal costs from the Company's subsidiaries involved with vertical integration of the Company's exploration and development activities and totaled $118 million, $123 million and $103 million during 2015, 2014 and 2013, respectively. All internal costs are included in the Company's cost of 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:

	2015	2014	2013
		(in millions)	
Sales	**$ 2,074**	$ 2,862	$ 2,404
Production (lifting) costs	**(989)**	(776)	(629)
Depreciation, depletion and amortization	**(1,028)**	(884)	(735)
Impairment of natural gas and oil properties	**(6,950)**	–	–
	(6,893)	1,202	1,040
Provision (benefit) for income taxes	**(2,619)**	457	416
Results of operations [(1)]	**$ (4,274)**	$ 745	$ 624

(1) Results of operations exclude the gain (loss) on derivatives, unsettled, on commodity derivative instruments. See Note 5 - 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 100%, 97% and 95% of the present worth of the Company's total proved reserves as of December 31, 2015, 2014 and 2013, 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 2015, 2014 and 2013 all of which were located in the United States:

	2015			2014			2013		
	Natural Gas (Bcf)	**Oil (MBbls)**	**NGL (MBbls)**	Natural Gas (Bcf)	Oil (MBbls)	NGL (MBbls)	Natural Gas (Bcf)	Oil (MBbls)	NGL (MBbls)
Proved reserves, beginning of year	**9,809**	**37,615**	**118,699**	6,974	373	–	4,017	244	–
Revisions of previous estimates	**(3,458)**	**(28,394)**	**(75,664)**	542	(14)	66	325	38	50
Extensions, discoveries and other additions	**546**	**1,367**	**6,274**	1,692	250	48	3,284	229	–
Production	**(899)**	**(2,265)**	**(10,702)**	(766)	(235)	(231)	(656)	(138)	(50)
Acquisition of reserves in place	**97**	**525**	**2,340**	1,367	37,246	118,816	4	–	–
Disposition of reserves in place	**(178)**	**(95)**	**–**	–	(5)	–	–	–	–
Proved reserves, end of year	**5,917**	**8,753**	**40,947**	9,809	37,615	118,699	6,974	373	–
Proved developed reserves:									
Beginning of year	**5,675**	**7,445**	**38,632**	4,237	372	–	3,196	243	–
End of year	**5,474**	**8,753**	**40,947**	5,675	7,445	38,632	4,237	372	–
Proved undeveloped reserves:									
Beginning of year	**4,134**	**30,170**	**80,067**	2,737	1	–	821	1	–
End of year	**443**	–	–	4,134	30,170	80,067	2,737	1	–

The Company's estimated proved natural gas and oil reserves were 6,215 Bcfe at year-end 2015, compared to 10,747 Bcfe at year-end 2014. The significant decrease in the Company's reserves in 2015 was primarily due to the decrease in commodity prices. In 2015, the Company's natural gas and liquids production was 976 Bcfe, up from 768 Bcfe in 2014. The increase in production in 2015 resulted primarily from a 140 Bcfe increase in net production from the Company's Southwest Appalachia properties, a 106 Bcf increase in net production from its Northeast Appalachia properties, partially offset by 29 Bcf and 9 Bcfe decreases in net production from its Fayetteville Shale and other properties, respectively. The Company had net downward revisions of 4,083 Bcfe and disposition of reserves in place of 179 Bcfe, partially offset by 592 Bcfe of proved reserve additions and 114 Bcfe of proved reserve additions from acquisitions. Of the reserve additions, 202 Bcf, 84 Bcfe, 129 Bcf and 1 Bcfe from the Company's Northeast Appalachia, Southwest Appalachia, Fayetteville Shale and other divisions, respectively, were proved developed and 138 Bcf, 4 Bcfe and 34 Bcf from its Northeast Appalachia, Southwest Appalachia and Fayetteville Shale divisions, respectively, were proved undeveloped. In 2015, downward reserve revisions resulting from lower prices totaled 2,315 Bcf, 1,875 Bcfe, 1,496 Bcf and 32 Bcfe in the Company's Northeast Appalachia, Southwest Appalachia, Fayetteville Shale and other divisions, respectively. The Company also had upward performance revisions in 2015 of 1,383 Bcf, 209 Bcfe, 10 Bcf and 33 Bcfe in its Northeast Appalachia, Southwest Appalachia, Fayetteville Shale and other divisions, respectively. 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 do not have a positive present value when discounted at 10%. These properties had a negative present value of $34 million when discounted at 10%. The Company made a final investment decision and is committed to developing these reserves within the next five years.

The Company's estimated proved natural gas and oil reserves were 10,747 Bcfe at year-end 2014, compared to 6,976 Bcfe at year-end 2013. The significant increase in the Company's reserves in 2014 was primarily due to the acquisition of approximately 413,000 net acres in Southwest Appalachia, successful development drilling programs in the Fayetteville Shale and Northeast Appalachia and upward performance revisions in Northeast Appalachia. In 2014, the Company's natural gas and liquids production was 768 Bcfe, up from 657 Bcfe in 2013. The increase in production in 2014 resulted primarily from a 103 Bcf increase in net production from the Company's Northeast Appalachia properties, an 8 Bcf increase in net production from its Fayetteville properties, and a 3 Bcfe increase in net production from its Southwest Appalachia properties, which more than offset a combined 3 Bcfe decrease in net production from its East Texas and Arkoma Basin properties. The Company replaced 591% of its production volumes with 1,693 Bcfe of proved reserve additions, net upward revisions of 543 Bcfe, and 2,304 Bcfe of proved reserve additions as a result of acquisitions primarily associated with acreage in Southwest Appalachia. Of the reserve additions, 283 Bcf, 246 Bcfe and 2 Bcfe from the Company's Fayetteville Shale, Northeast Appalachia and Brown Dense divisions, respectively, were proved developed and 573 Bcf and 589 Bcfe from its Fayetteville Shale and Northeast Appalachia divisions, respectively, were proved undeveloped. In 2014, upward reserve revisions resulting from higher gas prices totaled 38 Bcf, 10 Bcf and 6 Bcf in the Fayetteville Shale, Northeast Appalachia, and Ark-La-Tex division, respectively. The Company also had performance revisions in 2014 of (126) Bcf, 636 Bcf and (21) Bcf in its Fayetteville Shale, Northeast Appalachia, and Ark-La-Tex divisions, respectively. The Company's December 31, 2014 proved reserves include 181 Bcfe of proved undeveloped reserves from 60 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but did not have a positive present value when discounted at 10%. These properties had a negative present value of $28 million when discounted when at 10%.

The Company's estimated proved natural gas and oil reserves were 6,976 Bcfe at year-end 2013, compared to 4,018 Bcfe at year-end 2012. The overall increase in total estimated proved reserves in 2013 was primarily due to its successful development drilling programs in the Fayetteville Shale and Northeast Appalachia and the higher natural gas price environment compared to 2012. In 2013, the Company's natural gas and liquids production was 657 Bcfe, up from 565 Bcfe in 2012. The increase in production in 2013 resulted primarily from a 97 Bcf increase in production from the Company's Northeast Appalachia properties, a 1 Bcfe increase in net production from its New Ventures properties, and a 1 Bcf increase in net production from its Fayetteville Shale properties, which more than offset a combined 7 Bcfe decrease in net production from its East Texas and Arkoma Basin properties. The Company replaced 550% of its production volumes with 3,285 Bcfe of proved reserve additions, 557 Bcf, 386 Bcf and 2 Bcfe from the Company's Fayetteville Shale, Northeast Appalachia and Brown Dense divisions, respectively, were proved developed and 1,530 Bcf and 810 Bcf from its Fayetteville Shale and Northeast Appalachia divisions, respectively, were proved undeveloped. In 2013, upward reserve revisions resulting from higher gas prices totaled 191 Bcf, 35 Bcf and 21 Bcf in the Fayetteville Shale, Northeast Appalachia, and the Company's Ark-La-Tex division, respectively. The Company also had upward performance revision in 2013 of 16 Bcf, 62 Bcf and 1 Bcfe in the Fayetteville Shale, Northeast Appalachia, and the Company's New Ventures division, respectively. Additionally, the Company's reserves increased by 4 Bcf in 2013 as a result of the acquisition of natural gas leases and wells in Northeast Appalachia. The Company's December 31, 2013 proved reserves included 662 Bcfe of proved undeveloped reserves from 268 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but did not have a positive present value when discounted at 10%. These properties had a negative present value of $97 million when discounted when 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 and oil reserves as of December 31, 2015, 2014 and 2013 are calculated after income taxes and discounted using a 10% annual discount rate and do not purport to present the fair market value the Company's proved gas and oil reserves:

	2015	2014	2013
		(in millions)	
Future cash inflows	**$ 11,887**	$ 41,812	$ 22,624
Future production costs	**(7,376)**	(16,477)	(8,896)
Future development costs	**(792)**	(5,750)	(3,626)
Future income tax expense (1)	**–**	(4,743)	(3,223)
Future net cash flows	**3,719**	14,842	6,879
10% annual discount for estimated timing of cash flows	**(1,302)**	(7,299)	(3,143)
Standardized measure of discounted future net cash flows	**$ 2,417**	$ 7,543	$ 3,736

(1) The December 31, 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 $2.59 per MMBtu for natural gas, $46.79 per barrel for oil and $6.82 per barrel for NGLs in 2015, $4.35 per MMBtu for natural gas, $91.48 per barrel for oil and $23.79 per barrel for NGLs in 2014, and $3.67 per MMBtu for natural gas, $93.42 per barrel for oil and $43.45 per barrel for NGLs in 2013. 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 2015, 2014 and 2013:

	2015	2014	2013
		(in millions)	
Standardized measure, beginning of year	**$ 7,543**	$ 3,736	$ 2,051
Sales and transfers of natural gas and oil produced, net of production costs	**(1,082)**	(2,084)	(1,774)
Net changes in prices and production costs	**(8,075)**	1,192	1,853
Extensions, discoveries, and other additions, net of future production and development costs	**162**	1,049	1,454
Acquisition of reserves in place	**28**	1,897	5
Sales of reserves in place	**(244)**	–	–
Revisions of previous quantity estimates	**(1,385)**	622	349
Accretion of discount	**946**	513	232
Net change in income taxes	**1,915**	(522)	(1,120)
Changes in estimated future development costs	**2,007**	110	(196)
Previously estimated development costs incurred during the year	**875**	815	223
Changes in production rates (timing) and other	**(273)**	215	659
Standardized measure, end of year	**$ 2,417**	$ 7,543	$ 3,736

(5) 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 natural gas, oil and NGLs. These risks are managed by the Company's use of certain derivative financial instruments. As of December 31, 2015, the Company's derivative financial instruments consisted of basis swaps, fixed price call options and interest rate swaps. As of December 31, 2014, the Company's derivative financial instruments consisted of fixed price swaps, basis swaps, fixed price call options and interest rate swaps. 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.
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.
Fixed price call options	The Company sells fixed price call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, the Company pays the counterparty such excess on sold fixed price call options. If the market price settles below the fixed price of the call option, 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.

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 classified and accounted for as either a cash flow or a fair value hedge. Accounting for qualifying hedges requires a derivative's gains and losses to be recorded either in earnings or as a component of other comprehensive income. In the period of settlement, the Company recognizes the gains and losses from these qualifying hedges in operating revenues. Gains and losses on derivatives that are not designated for hedge accounting treatment, or that do not meet hedge accounting requirements, are recorded in earnings as a component of gain (loss) on derivatives. Within the gain (loss) on derivatives component of the statement of operations are gains (losses) on derivatives excluding derivatives, settled and gains (losses) on derivatives, settled. The Company calculates gains (losses) on derivatives, settled, as the summation of gains and losses on positions which have settled within the period.

The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy 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 balance sheet classification of the assets related to derivative financial instruments are summarized below as of December 31, 2015 and 2014:

	Derivative Assets			
	December 31, 2015		December 31, 2014	
	Balance Sheet Classification	**Fair Value**	Balance Sheet Classification	Fair Value
	(in millions)			
Derivatives designated as hedging instruments:				
Fixed price swaps	Derivative assets	$ **–**	Derivative assets	$ 165
Total derivatives designated as hedging instruments		$ **–**		$ 165
Derivatives not designated as hedging instruments:				
Basis swaps	Derivative assets	$ **3**	Derivative assets	$ 9
Fixed price swaps	Derivative assets	**–**	Derivative assets	163
Basis swaps	Other long-term assets	**–**	Other long-term assets	1
Interest rate swaps	Other long-term assets	**–**	Other long-term assets	1
Total derivatives not designated as hedging instruments		$ **3**		$ 174
Total derivative assets		$ **3**		$ 339

	Derivative Liabilities			
	December 31, 2015		December 31, 2014	
	Balance Sheet Classification	**Fair Value**	Balance Sheet Classification	Fair Value
	(in millions)			
Derivatives not designated as hedging instruments:				
Basis swaps	Derivative liabilities	$ **–**	Derivative liabilities	$ 4
Fixed price call options	Derivative liabilities	**–**	Derivative liabilities	2
Interest rate swaps	Derivative liabilities	**3**	Derivative liabilities	3
Fixed price call options	Other long-term liabilities	**–**	Other long-term liabilities	10
Basis swaps	Other long-term liabilities	**–**	Other long-term liabilities	2
Interest rate swaps	Other long-term liabilities	**2**	Other long-term liabilities	2
Total derivatives not designated as hedging instruments		$ **5**		$ 23
Total derivative liabilities		$ **5**		$ 23

Cash Flow Hedges

The Company has certain fixed price swaps that are designated for hedge accounting. The reporting of gains and losses on cash flow derivative hedging instruments depends on whether the gains or losses are effective at offsetting changes in the cash flows of the hedged item. The effective portion of the gains and losses on the derivative hedging instruments are recorded in other comprehensive income until recognized in earnings during the period that the hedged transaction takes place. The ineffective portion of the gains and losses from the derivative hedging instrument are recognized in earnings immediately and had an inconsequential impact to the consolidated statement of operations as of December 31, 2015 and 2014.

The amount included in accumulated other comprehensive income will be relieved over time and recognized in the statement of operations as the physical transactions being hedged occur. Gains or losses from derivative instruments designated as cash flow hedges are reflected as adjustments to revenues in the consolidated statements of operations. Volatility in net income, comprehensive income and accumulated other comprehensive income may occur in the future as a result of the Company’s derivative activities. As of December 31, 2015, the Company had no fixed price swap derivatives and no accumulated other comprehensive income related to its hedging activities.

The following tables summarize the before tax effect of all fixed price swaps designated for hedge accounting on the consolidated financial statements for the years ended December 31, 2015 and 2014.

Derivative Instrument	Gain Recognized in Other Comprehensive Income (Effective Portion) For the years ended December 31, 2015	2014
	(in millions)	
Fixed price swaps	$ **45**	$ 122

Derivative Instrument	Classification of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion) For the years ended December 31, 2015	2014
		(in millions)	
Fixed price swaps	Gas Sales	$ **209**	$ (26)

Other Derivative Contracts

For other derivative contracts, the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item are recognized in earnings immediately through gain (loss) on derivatives. Although the Company's basis swaps meet the objective of managing commodity price exposure, these trades are typically not entered into concurrent with the Company's derivative instruments that qualify as cash flow hedges and therefore do not generally qualify for hedge accounting. Basis swap derivative instruments that are not designated for hedge accounting are recorded on the balance sheet at their fair values under derivative assets, other long-term assets, other current liabilities, and other long-term liabilities, as applicable and all gains and losses related to these contracts are recognized immediately in the consolidated statements of operations as a component of gain (loss) on derivatives. As of December 31, 2015, the Company had 5 Bcf of basis swaps on 2016 natural gas production that were not designated for hedge accounting.

As of December 31, 2015, the Company had fixed price call options on 120 Bcf of natural gas production in 2016 that do not qualify and are not designated for hedge accounting.

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. Changes in the fair value of the interest rate swaps are included in gain (loss) on derivatives in the consolidated statements of operations.

The following tables summarize the before tax effect of fixed price swaps, basis swaps, fixed price call options and interest rate swaps not designated for hedge accounting on the consolidated statements of operations for the years ended December 31, 2015 and 2014.

Derivative Instrument	Consolidated Statements of Operations Classification of Gain (Loss) on Derivatives, Net of Settlement	Gain (Loss) on Derivatives, Excluding Derivatives, Settled Recognized in Earnings For the years ended December 31, 2015	2014
		(in millions)	
Basis swaps	Gain on Derivatives	**$ (2)**	$ (7)
Fixed price call options	Gain on Derivatives	**13**	18
Fixed price swaps	Gain on Derivatives	**(164)**	126
Interest rate swaps	Gain on Derivatives	**(2)**	(7)

Derivative Instrument	Consolidated Statements of Operations Classification of Gain (Loss) on Derivatives, Settled (1)	Gain (Loss) on Derivatives, Settled (1) Recognized in Earnings For the years ended December 31, 2015	2014
		(in millions)	
Basis swaps	Gain on Derivatives	**$ (2)**	$ 12
Fixed price swaps	Gain on Derivatives	**208**	(2)
Interest rate swaps	Gain on Derivatives	**(4)**	(1)

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

(6) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME

The following tables detail the components of accumulated other comprehensive income (loss) and the related tax effects for the year ended December 31, 2015:

	For the year ended December 31, 2015			
	Gains (Losses) on Cash Flow Hedges	Pension and Other Postretirement	Foreign Currency	Total
	(in millions) (1)			
Beginning balance, December 31, 2014	$ 98	$ (24)	$ (12)	$ 62
Other comprehensive income (loss) before reclassifications	29	–	(11)	18
Amounts reclassified from/to other comprehensive income (2)	(127)	(1)	–	(128)
Net current-period other comprehensive income (loss)	(98)	(1)	(11)	(110)
Ending balance, December 31, 2015	**$ –**	**$ (25)**	**$ (23)**	**$ (48)**

(1) All amounts are net of tax.
(2) See separate table below for details about these reclassifications.

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statements of Operations	Amount Reclassified from/to Accumulated Other Comprehensive Income
		For the year ended December 31, 2015
		(in millions)
Cash flow hedges		
Settlements	Gas sales	$ (209)
Ineffectiveness	Gain on derivatives	1
	Provision (benefit) for income taxes	(81)
	Net income (loss)	$ (127)
Pension and other postretirement [1]		
Net actuarial loss [2]		$ (3)
Amortization of prior service cost and net loss	General and administrative expenses	$ 2
	Provision (benefit) for income taxes	–
	Net income (loss)	$ (1)
Total reclassifications for the period	Net income (loss)	$ (128)

(1) See Note 12 for additional details regarding the Company's retirement and employee benefit plans.
(2) Net actuarial loss had no impact on the consolidated statement of operations.

(7) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2015 and 2014 were as follows:

	December 31, 2015		December 31, 2014	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(in millions)			
Cash and cash equivalents	**$ 15**	**$ 15**	$ 53	$ 53
Credit facility	**116**	**116**	300	300
Term loan facility	**750**	**750**	500	500
Bridge facility	**–**	**–**	4,500	4,500
Senior notes	**3,863**	**2,672**	1,667	1,751
Derivative instruments, net	**(2)**	**(2)**	316	316

The carrying values of cash and cash equivalents, accounts receivable, accounts payable, other current assets and 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 unsecured revolving credit facility, term loan facility and previously, bridge 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) and 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, 2015 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 fixed price call options (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. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively. However, such changes would not have a significant impact.

Assets and liabilities measured at fair value on a recurring basis are summarized below (in millions):

	December 31, 2015			
	Fair Value Measurements Using:			
	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	**$ –**	**$ –**	**$ –**	**$ –**
Interest rate swap assets	**–**	**–**	**–**	**–**
Basis swap assets	**–**	**–**	**3**	**3**
Interest rate swap liabilities	**–**	**(5)**	**–**	**(5)**
Basis swap liabilities	**–**	**–**	**–**	**–**
Fixed price call option liabilities	**–**	**–**	**–**	**–**
Total	**$ –**	**$ (5)**	**$ 3**	**$ (2)**

	December 31, 2014			
	Fair Value Measurements Using:			
	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	$ –	$ 328	$ –	$ 328
Interest rate swap assets	–	1	–	1
Basis swap assets	–	–	10	10
Interest rate swap liabilities	–	(5)	–	(5)
Basis swap liabilities	–	–	(6)	(6)
Fixed price call option liabilities	–	–	(12)	(12)
Total	$ –	$ 324	$ (8)	$ 316

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, 2015 and 2014. 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, 2015 and December 31, 2014.

	For the years ended December 31,	
	2015	2014
	(in millions)	
Balance at beginning of year	**$ (8)**	$ (19)
Total gains (losses):		
Included in earnings	**9**	23
Included in other comprehensive income	**–**	–
Purchases, issuances, and settlements:		
Purchases	**–**	–
Issuances	**–**	–
Settlements	**2**	(12)
Transfers into/out of Level 3	**–**	–
Balance at end of year	**$ 3**	$ (8)
Change in gains (losses) included in earnings relating to derivatives still held as of December 31	**$ 11**	$ 11

See Note 12 – Retirement and Employee Benefit Plans for a discussion of the fair value measurement of the Company's pension plan assets.

(8) DEBT

The components of debt as of December 31, 2015 and 2014 consisted of the following:

	2015	2014
	(in millions)	
Short-term debt:		
7.15% Senior Notes due May 2018	**$ 1**	$ 1
Variable rate (1.515% at December 31, 2014) bridge facility, due December 2015	**–**	4,500
Total short-term debt	**1**	4,501
Long-term debt:		
Variable rate (1.886% and 1.515% at December 31, 2015 and December 31, 2014, respectively) credit facility, expires December 2018	**116**	300
Variable rate (1.545% at December 31, 2014) term loan facility, due December 2016	**–**	500
Variable rate (1.775% at December 31, 2015) term loan facility, due November 2018	**750**	–
7.35% Senior Notes due October 2017	**15**	15
7.125% Senior Notes due October 2017	**25**	25
3.3% Senior Notes due January 2018	**350**	–
7.5% Senior Notes due February 2018	**600**	600
7.15% Senior Notes due May 2018	**26**	27
4.05% Senior Notes due January 2020	**850**	–
Unamortized discount	**(1)**	–
4.10% Senior Notes due March 2022	**1,000**	1,000
Unamortized discount	**(1)**	(1)
4.95% Senior Notes due January 2025	**1,000**	–
Unamortized discount	**(2)**	–
Total long-term debt	**4,728**	2,466
Total debt	**$ 4,729**	$ 6,967

The following is a summary of scheduled long-term debt maturities by year as of December 31, 2015 (in millions):

2016	1
2017	41
2018	1,841
2019	–
2020	850
Thereafter	2,000
	$ 4,733

Commercial Paper

In April 2015, the Company entered into a commercial paper program which allowed it to issue up to $2.0 billion in commercial paper, provided that outstanding borrowings from its commercial paper program, combined with outstanding borrowings under our revolving credit facility, not exceed $2.0 billion. The commercial paper issuance had terms of up to 397 days and carried interest at rates agreed upon at the time of each issuance. As of December 31, 2015, the Company had no outstanding issuances under its commercial paper program and had no plans of utilizing the commercial paper market after the first quarter of 2016.

Public Offering of 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 proceeds from this offering were used to repay the remaining principal and interest outstanding under the Company's $4.5 billion 364-day bridge term loan facility, which was first reduced with proceeds from the Company's concurrent underwritten public offerings of common and preferred stock, and were also used to repay a portion of amounts outstanding under the Company's revolving credit facility. As a result of this repayment, the Company expensed $47 million of short-term unamortized debt issuance costs related to the bridge facility in January 2015 recognized in other interest charges on the consolidated statement of operations for the year ended December 31, 2015. The Notes were sold to the public at a price of 99.949% of their face value for the 2018 Notes, 99.897% of their face value for the 2020 Notes and 99.782% of their face value for the 2025 Notes. The interest rates on the Notes is determined based upon the Company's public debt ratings from S&P and Moody's. Downgrades from either rating agency increase interest costs by 25.0 basis points per downgrade level on the following semi-annual bond interest payment. In February 2016, S&P and Moody's downgraded the Company's credit ratings, increasing the interest rates on these notes by 125.0 basis points effective July 2016.

Credit and Term Facilities

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. The interest rate on the term loan facility is determined based upon the Company's public debt ratings from S&P and Moody's and was 137.5 basis points over the London Interbank Offered Rate ("LIBOR") as of December 31, 2015. Based on the February 2016 downgrades from S&P and Moody's the Company's interest rate on the term loan increased to 162.5 basis points over LIBOR. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business.

The Company's revolving credit facility entered into in December 2013, provides a borrowing capacity of up to $2.0 billion and matures in December 2018, with options for two one-year extensions with participating lender approval. The amount available under the revolving credit facility may be increased by $500 million upon the Company's agreement with its participating lenders. The interest rate on the revolving credit facility is calculated based upon the Company's public debt ratings from S&P and Moody's and was 150.0 and 137.5 basis points over LIBOR as of December 31, 2015 and 2014, respectively. Based on the February 2016 downgrades from S&P and Moody's the Company's interest rate on its revolving credit facility increased to 200.0 basis points over LIBOR.

The revolving credit facility and term loan facility are unsecured and are not guaranteed by any subsidiaries of the Company. The revolving credit facility and term loan facility contain covenants imposing certain restrictions on the Company, including a financial covenant under which Southwestern may not issue 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. As of December 31, 2015, the Company's adjusted capital structure was 38% debt, 62% equity and was in compliance with the covenants of its revolving credit facility, term loan facility and other debt agreements.

In December 2014, the Company entered into a $500 million unsecured two-year term loan credit agreement with various lenders. The term loan facility, prior to its termination, required prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business. The term loan facility was repaid in full in April 2015 with proceeds from the divestiture of the Company's northeast Pennsylvania gathering assets and borrowings under the Company's revolving credit facility.

Chesapeake Property Acquisition Financing

On December 19, 2014, the Company entered into a $4.5 billion unsecured 364-day bridge term loan credit agreement with various lenders. The bridge facility requires prepayments under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business or for specified uses. The Company repaid the $4.5 billion outstanding and terminated the bridge facility in January 2015 with net proceeds of $669 million and $1.7 billion from common stock and depositary share offerings, respectively, and $2.2 billion from senior note offerings with the difference utilized to pay down amounts under the revolving credit facility.

(9) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

The Company has 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. As of December 31, 2015, future payments under non-cancelable firm transportation agreements are approximately $623 million in 2016, $691 million in 2017, $712 million in 2018, $751 million in 2019, $702 million in 2020 and $5,402 million thereafter. Of the total $8.9 billion, 38% 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 has guarantee obligations of up to $960 million of that amount. Additionally, $100 million relates to demand charges under firm transportation agreements under which the Company has the option to reduce its commitment by 531 Bcf beginning in 2018.

The Company has 14 leases for pressure pumping equipment for its E&P operations under leases that expire between December 2017 and March 2018. The Company's current aggregate annual payment under the leases is approximately $8 million. The Company has 7 leases for drilling rigs for its E&P operations that expire in 2020. The Company's current aggregate annual payment under the leases is 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 for their share of fracture stage charges.

The Company leases compressors, aircraft, vehicles, office space and equipment under non-cancelable operating leases expiring through 2027. As of December 31, 2015, future minimum payments under these non-cancelable leases accounted for as operating leases are approximately $71 million in 2016, $64 million in 2017, $44 million in 2018, $38 million in 2019, $30 million in 2020 and $28 million thereafter.

The Company also has commitments for compression services related to its Midstream Services and E&P segments. As of December 31, 2015, future minimum payments under these non-cancelable agreements are approximately $21 million in 2016, $14 million in 2017, $8 million in 2018, $5 million in 2019, and $1 million in 2020.

In the first quarter of 2010, the Company was awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require the Company to make certain capital investments in New Brunswick of approximately $47 million Canadian dollars in the aggregate over the license periods. In order to obtain the licenses, the Company provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of $45 million Canadian dollars. The promissory notes secure the Company's capital expenditure obligations under the licenses and are returnable to the Company to the extent the Company performs such obligations. If the Company fails to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company commenced its Canada exploration program in 2010 and, as of December 31, 2015 has invested $45 million Canadian dollars, or $44 million US dollars, in New Brunswick towards the Company's commitment, fully covering the promissory notes held by the Province of New Brunswick. No liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of December 31, 2015 and its future investment plans. In December 2014, New Brunswick's provincial government announced its intent to impose a moratorium on hydraulic fracturing in the province, and, on March 27, 2015, the provincial legislature approved enabling legislation. The Company has been granted an extension of its licenses. The provincial government has announced a list of conditions that must be met before the moratorium can be lifted, but because these conditions are subjective and the government has discretion whether to grant an extension, the Company cannot predict the duration of the moratorium or whether it will continue beyond the expiration of the licenses, as their terms have been, or in the future may be, extended. Unless and until the moratorium is lifted, the Company will not be able to continue with its program in New Brunswick. If the licenses expire before the moratorium is lifted or the Company can complete its program, the Company may be required to write off its investment.

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 other litigation, claims and proceedings that have arisen 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 the Company's 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 the Company's financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated.

<u>Tovah Energy</u>

In February 2009, one of the Company's subsidiaries was added as a defendant in a case then styled Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et al., pending in the 273rd District Court in Shelby County, Texas. By the time of trial in December 2010, Ms. Berry-Helfand (the only remaining plaintiff) alleged that, in 2005, she provided the Company's subsidiary with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that the Company's subsidiary refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, she alleged various statutory and common law claims, including, but not limited to, claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by the Company's subsidiary between February 2005 and February 2006. She also sought disgorgement of the Company's subsidiary's profits. A former associate of the plaintiff intervened in the matter claiming to have helped develop the prospect years earlier.

The jury found in favor of the plaintiff and the intervenor with respect to all of the statutory and common law claims and awarded $11 million in compensatory damages but no special, punitive or other damages. Separately, the jury determined that the Company's subsidiary's profits for purposes of disgorgement, if ordered as a remedy, were $382 million. (Disgorgement of profits is an equitable remedy determined by the judge, and it is within the judge's discretion to award none, some or all of unlawfully obtained profits.) In August 2011, a judgment was entered pursuant to which the plaintiff and the intervenor were entitled to recover approximately $11 million in actual damages and approximately $24 million in disgorgement as well as prejudgment interest and attorneys' fees, which currently are estimated to be up to $9 million, and all costs of court of the plaintiff and intervenor.

Both sides appealed and in July 2013, the Tyler Court of Appeals ordered that (1) the judgment awarding the plaintiff and the intervenor $24 million as disgorgement of illicit gains be reversed and judgment rendered that they take nothing, (2) the award of $11 million for actual damages, insofar as it is based on the jury's findings of breach of fiduciary duty, fraud, breach of contract, and theft of trade secret is reversed and judgment rendered that the plaintiff and the intervenor take nothing under those theories of recovery, (3) the award of $11 million to the plaintiff and the intervenor as damages for misappropriation of trade secrets is affirmed, (4) the case be remanded to the trial court for a determination and award of attorney's fees for the Company's subsidiary as the prevailing party under the Texas Theft Liability Act, and (5) in all other respects, the judgment is affirmed. All parties petitioned for rehearing. The Tyler Court of Appeals denied rehearing in November 2013.

The Company's subsidiary filed a petition for review in the Supreme Court of Texas in February 2014. The plaintiff and the intervenor filed a cross-petition for review in April 2014, but conditioned their filing on the court's granting the Company's subsidiary's petition for review; i.e., if the court denies the Company's subsidiary's petition for review, then the plaintiff and the intervenor are not seeking further review of the court of appeals' judgment. The Supreme Court granted the parties' petitions and heard oral argument on the case in October 2015 but has not yet issued a decision. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate matters, and after considering the advice of counsel, the Company has determined that, although reasonably possible, a materially adverse final outcome to this action is not probable. As such, the Company has not accrued any amounts with respect to this action. If the Supreme

Court affirms all aspects of the court of appeals' judgment, then the Company's subsidiary would owe the $11 million in damages, plus interest and attorneys' fees, offset by any award of attorneys' fees for its prevailing on the theft count. The Company's assessment may change in the future depending on the Supreme Court's decision, and such a re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

Arkansas Royalty Litigation

Certain of the Company's subsidiaries are defendants in three cases, two filed in Arkansas state court in 2010 and 2013 and one in federal court in 2014, on behalf of putative classes of royalty owners on some of the Company's leases located in Arkansas. The chief complaint in all three cases is that one of the Company's subsidiaries underpaid the royalty owners by, among other things, deducting from royalty payments costs for gathering, transportation, and compression of natural gas in excess of what is permitted by the relevant leases. In September and October 2014 the judges in the two Arkansas state actions entered orders certifying classes of royalty owners who are citizens of Arkansas. The Company's subsidiaries are appealing those orders. In one of those cases, the class representative has died, and the case has been remanded to the trial court for possible substitution of a new class representative.

On November 17, 2015, the court in the federal case denied the plaintiff's motion to certify a class of royalty owners not included in either of the two state cases. That court is still considering a motion by the Company's subsidiaries to certify a broader class that would, among other things, encompass all cost-bearing royalty owners with leases for property in the Fayetteville Shale. The federal court has not yet ruled on certification. The plaintiff in the federal case presented two alternative damages theories. Under one theory, plaintiffs have asserted that obligations to affiliates are not "incurred" and therefore the exploration subsidiary was not entitled to deduct any post-production costs; the federal court has granted partial summary judgment for the Company's subsidiaries on this theory. Under another theory, plaintiffs assert that the gathering and treating rates it deducted from royalty payments exceeded the affiliates' actual costs or otherwise were not reasonable. The plaintiffs have not disclosed a specific damage calculation for any putative class, but based on the putative class representative's disclosure regarding the calculation of claimed damages, class-wide damages could exceed $100 million. Trial in the federal case is currently set to begin March 15, 2016.

In addition, in September 2015 three cases were filed in Arkansas state court on behalf of a total of 248 individually named plaintiffs. Each case asserts complaints that are in substance virtually identical to the above-described case. The Company and its subsidiaries have removed two of the cases to federal court, and those cases have been assigned to the court in which the above-described federal case is pending. All three cases have been stayed.

Management believes that, in all of the above cases, the deductions from royalty payments as calculated are permitted and intends to defend the cases vigorously. The Company's assessment may change in the future due to the occurrence of certain events, such as adverse judgments, and such a re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

Indemnifications

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

(10) INCOME TAXES

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

	2015	2014	2013
		(in millions)	
Current:			
Federal	**$ 1**	$ 11	$ (12)
State	**(3)**	10	1
	(2)	21	(11)
Deferred:			
Federal	**(1,697)**	501	408
State	**(304)**	2	88
Foreign	**(2)**	1	1
	(2,003)	504	497
Provision (benefit) for income taxes	**$ (2,005)**	$ 525	$ 486

The provision for income taxes was an effective rate of 31% in 2015, 36% in 2014 and 41% in 2013. 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:

	2015	2014	2013
		(in millions)	
Expected provision (benefit) at federal statutory rate	**$ (2,296)**	$ 507	$ 417
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	**(194)**	58	53
Nondeductible expenses	**–**	3	3
State rate redetermination	**–**	(48)	4
Change in valuation allowance	**488**	5	–
Other	**(3)**	–	9
Provision (benefit) for income taxes	**$ (2,005)**	$ 525	$ 486

Our effective tax rate decreased in 2015 as compared with 2014, primarily due to the change in valuation allowance.

The components of the Company's deferred tax balances as of December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Deferred tax liabilities:		
Differences between book and tax basis of property	**$ 216**	$ 2,504
Derivative activity	**–**	122
Other	**9**	21
	225	2,647
Deferred tax assets:		
Accrued compensation	**28**	23
Alternative minimum tax credit carryforward	**125**	131
Accrued pension costs	**19**	17
Asset retirement obligations	**77**	79
Net operating loss carryforward	**445**	323
Other	**24**	19
	718	592
Valuation allowance	**(493)**	(5)
Net deferred tax liability	**$ –**	$ 2,060

In 2015, the Company paid less than $1 million in state income taxes and did not pay federal income taxes. In 2014, the Company paid $14 million in state income taxes and paid $14 million in federal income taxes. The Company's net operating loss carryforward as of December 31, 2015 was $1,278 million and $789 million for federal and state reporting purposes, respectively, the majority of which will expire between 2028 and 2035. Additionally, the Company has an income tax net operating loss carryforward related to its Canadian operations of $51 million, with expiration dates of 2030 through 2035. The Company also had an alternative minimum tax credit carryforward of $125 million and a statutory depletion carryforward of $13 million as of December 31, 2015.

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. Due to the material write-downs of the carrying value of our natural gas and oil properties, the Company ended the year in a net deferred tax asset position. We believe it is more likely than not that these deferred tax assets will not be realized, and recorded a $488 million tax expense for the increase in our valuation allowance. The net change in valuation allowance is reflected as a component of income tax expense. 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. The amount of the deferred tax asset considered realizable, however, could be adjusted based on changes in subjective estimates of future taxable income or if objective negative evidence is no longer present.

Deferred tax assets relating to tax benefits of employee stock option grants have been reduced to reflect exercises. Some exercises resulted in tax deductions in excess of previously recorded benefits based on the option value at the time of the grant ("windfalls"). Although these additional tax benefits or "windfalls" are reflected in net operating loss carryforwards, the additional tax benefit associated with the windfall is not recognized until the deduction reduces taxes payable. Accordingly, since the tax benefit does not reduce the Company's current taxes payable in 2015 due to net operating loss carryforwards, these "windfall" tax benefits are not reflected in its net operating losses in deferred tax assets for 2015. Windfalls included in net operating loss carryforwards but not reflected in deferred tax assets for 2015 were $149 million.

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, 2015, the amount of unrecognized tax benefits related to alternative minimum tax was $37 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, 2015, the Company had accrued a liability of $2 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:

	2015	2014
	(in millions)	
Unrecognized tax benefits at beginning of period	**$ 44**	**$ –**
Additions based on tax positions related to the current year	**7**	**15**
Additions to tax positions of prior years	**–**	**29**
Reductions to tax positions of prior years	**(14)**	**–**
Unrecognized tax benefits at end of period	**$ 37**	**$ 44**

The income tax years 2012 to 2015 remain open to examination by the major taxing jurisdictions to which the Company is subject.

(11) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the Company's 2015 and 2014 activity related to asset retirement obligations:

	2015	2014
	(in millions)	
Asset retirement obligation at January 1	**$ 207**	$ 134
Accretion of discount	**11**	7
Obligations incurred [(1)]	**17**	64
Obligations settled/removed [(2)]	**(30)**	(4)
Revisions of estimates	**(4)**	6
Asset retirement obligation at December 31	**$ 201**	$ 207
Current liability	**10**	9
Long-term liability	**191**	198
Asset retirement obligation at December 31	**$ 201**	$ 207

(1) Obligations incurred in 2014 include $42 million related to the Chesapeake Property Acquisition.

(2) Obligations settled/removed in 2015 include $25 million related to asset divestitures.

(12) 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, $3 million and $3 million of contribution expense in 2015, 2014 and 2013, respectively. Additionally, the Company capitalized $4 million, $3 million and $3 million of contributions in 2015, 2014 and 2013, 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.

The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets, and funded status as of December 31, 2015 and 2014:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	**2015**	2014
	(in millions)			
Change in benefit obligations:				
Benefit obligation at January 1	**$ 134**	$ 103	**$ 18**	$ 12
Service cost	**16**	13	**3**	2
Interest cost	**6**	5	**1**	1
Participant contributions	**–**	–	**–**	–
Actuarial loss	**(7)**	21	**(2)**	3
Benefits paid	**(11)**	(8)	**–**	–
Plan amendments	**–**	–	**–**	–
Settlements	**–**	–	**–**	–
Benefit obligation at December 31	**$ 138**	$ 134	**$ 20**	$ 18

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	**2015**	2014
	(in millions)			
Change in plan assets:				
Fair value of plan assets at January 1	**$ 108**	$ 99	**$ –**	$ –
Actual return on plan assets	**(1)**	5	–	–
Employer contributions	**12**	12	–	–
Participant contributions	–	–	–	–
Benefits paid	**(11)**	(8)	–	–
Settlements	–	–	–	–
Fair value of plan assets at December 31	**$ 108**	$ 108	**$ –**	$ –
Funded status of plans at December 31	**$ (30)**	$ (26)	**$ (20)**	$ (18)

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 change in accumulated other comprehensive income related to the pension plans was a loss of $2 million ($2 million after tax) for the year ended December 31, 2015 and a loss of $23 million ($14 million after tax) for the year ended December 31, 2014. The change in accumulated other comprehensive income related to the other postretirement benefit plan was a gain of $1 million ($1 million after tax) for the year ended December 31, 2015 and was a loss of $2 million ($1 million after tax) for the year ended December 31, 2014. Included in accumulated other comprehensive income as of December 31, 2015 and 2014 was a $42 million loss ($25 million net of tax) and a $41 million loss ($24 million net of tax), respectively, related to the Company's pension and other postretirement benefit plans. For the year ended December 31, 2015, $3 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 2016 is a $2 million net loss.

The pension plans' projected benefit obligation, accumulated benefit obligation and fair value of plan assets as of December 31, 2015 and 2014 are as follows:

	2015	2014
	(in millions)	
Projected benefit obligation	$ 138	$ 134
Accumulated benefit obligation	135	129
Fair value of plan assets	108	108

Pension and other postretirement benefit costs include the following components for 2015, 2014 and 2013:

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
	(in millions)					
Service cost	$ 16	$ 13	$ 14	$ 3	$ 2	$ 2
Interest cost	6	5	4	1	1	1
Expected return on plan assets	(9)	(7)	(6)	–	–	–
Amortization of transition obligation	–	–	–	–	–	–
Amortization of prior service cost	–	–	–	–	–	–
Amortization of net loss	2	1	2	–	–	–
Net periodic benefit cost	15	12	14	4	3	3
Settlements and curtailments	–	–	–	–	–	–
Total benefit cost	$ 15	$ 12	$ 14	$ 4	$ 3	$ 3

Amounts recognized in other comprehensive income for the year ended December 31, 2015 were as follows:

	Pension Benefits	Other Postretirement Benefits
	(in millions)	
Net actuarial (loss) gain arising during the year	$ (4)	$ 1
Amortization of prior service cost	–	–
Amortization of net loss	2	–
Settlements	–	–
Tax effect	–	–
	$ (2)	$ 1

The assumptions used in the measurement of the Company's benefit obligations as of December 31, 2015 and 2014 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
Discount rate	4.60 %	4.25 %	4.60 %	4.25 %
Rate of compensation increase	3.50 %	4.50 %	n/a	n/a

The assumptions used in the measurement of the Company's net periodic benefit cost for 2015, 2014 and 2013 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Discount rate	4.25 %	5.00 %	4.00 %	4.25 %	5.00 %	4.00 %
Expected return on plan assets	7.00 %	7.00 %	7.00 %	n/a	n/a	n/a
Rate of compensation increase	4.50 %	4.50 %	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 2015 and 2014:

	2015	2014
Health care cost trend assumed for next year	**8 %**	8 %
Rate to which the cost trend is assumed to decline	**5 %**	5 %
Year that the rate reaches the ultimate trend rate	**2034**	2033

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:

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

Pension Payments and Asset Management

In 2015, the Company contributed $12 million to its pension plans and $0.2 million to its other postretirement benefit plan. As of February 23, 2016 the Company is uncertain of its required 2016 contributions to its pension and other postretirement benefit plans as a result of the recent reduction in workforce, which was announced in January of 2016 and is expected to be completed by the end of the first quarter of 2016. As a result of the workforce reduction, the Company continues to evaluate its pension and other postretirement benefit funding requirements and will disclose its funding plans once reasonably determined.

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

Pension Benefits		Other Postretirement Benefits	
	(in millions)		
2016	$ 8	2016	$ 1
2017	9	2017	1
2018	10	2018	1
2019	11	2019	1
2020	10	2020	2
Years 2021-2025	67	Years 2021-2025	11

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 benefit payment of obligations to participants, retirees and beneficiaries. The Benefits Administration Committee of the Company 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, 2015, 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:		
Equity securities:	Target	Actual
U.S. Equity(1)	35 %	36 %
Non-U.S. Developed Equity(2)	30 %	29 %
Emerging Markets Equity(3)	5 %	5 %
Opportunistic(4)	– %	– %
Fixed income(5)	28 %	28 %
Cash(6)	2 %	2 %
Total	100 %	100 %

(1) Asset category above 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) Asset category above includes Non-U.S. equity securities in the table below.
(3) Asset category above includes Emerging markets equity securities below.
(4) Asset category above includes none of the securities in the table below.
(5) Asset category above includes Fixed income pension plan assets in the table below.
(6) Asset category above includes Cash and cash equivalents pension plan assets in the table below.

Utilizing the fair value hierarchy described in Note 7 – Fair Value Measurements, the Company's fair value measurement of pension plan assets as of December 31, 2015 are as follows:

Asset category:	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(in millions)		
Equity securities:				
U.S. large cap growth equity(1)	$ 9	$ 9	$ –	$ –
U.S. large cap value equity(2)	9	9	–	–
U.S. large cap core equity(3)	18	–	18	–
U.S. small cap equity(4)	3	3	–	–
Non-U.S. equity(5)	31	31	–	–
Emerging markets equity(6)	5	5	–	–
Fixed income (7)	31	–	31	–
Cash and cash equivalents	2	2	–	–
Total	$ 108	$ 59	$ 49	$ –

(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) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.
(4) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
(5) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.
(6) An institutional fund that invests primarily in the equity securities of companies domiciled in emerging markets.
(7) 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.

Utilizing the fair value hierarchy described in Note 7 – Fair Value Measurements, the Company's fair value measurement of pension plan assets at December 31, 2014 are as follows:

Asset category:	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(in millions)		
Equity securities:				
U.S. large cap growth equity(1)	$ 8	$ 8	$ –	$ –
U.S. large cap value equity(2)	9	9	–	–
U.S. large cap core equity(3)	19	–	19	–
U.S. small cap equity(4)	3	3	–	–
Non-U.S. equity(5)	29	29	–	–
Emerging markets equity(6)	5	5	–	–
Fixed income (7)	31	–	31	–
Cash and cash equivalents	4	4	–	–
Total	$ 108	$ 58	$ 50	$ –

(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) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.
(4) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
(5) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.
(6) An institutional fund that invests primarily in the equity securities of companies domiciled in emerging markets.
(7) An institutional fund that seeks 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.

The Company's pension plan assets that are classified as Level 1 are due to the pension plan's investments comprising 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. The Company's Level 2 pension plan assets represent investments in institutional funds. These equity securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by the investment managers. 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.

(13) STOCK-BASED COMPENSATION

The Southwestern Energy Company 2013 Incentive Plan ("2013 Plan") was adopted in February 2013 and approved by stockholders in May 2013. 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 replaced the Southwestern Energy Company 2004 Stock Incentive Plan, the Southwestern Energy Company 2000 Stock Incentive Plan ("2000 Plan"), and the Southwestern Energy Company 2002 Employee Stock Incentive Plan ("2002 Plan") but did not affect prior awards under those plans which remained valid and some of which are still outstanding. The awards under the prior plans have been adjusted for stock splits as permitted under such plans.

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 20,500,000 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.

As initially adopted, the 2004 Plan, the 2000 Plan, and the 2002 Plan provided for grants of options, stock appreciation rights, shares of phantom stock, and shares of restricted stock that in the aggregate did not exceed 16,800,000, 1,250,000, and 300,000 shares, respectively, to employees who are not officers or directors of the Company under provisions of Section 16 of the Securities Exchange Act of 1934, as amended. The Company may utilize treasury shares, if available, or authorized but unissued shares when a stock option is exercised or when restricted stock is granted.

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 for awards under both the 2013 Plan and the 2004 Plan and ten years from the date of grant for awards under all other plans. 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 on or after December 6, 2013 immediately vest upon death, disability, or retirement (subject to a minimum of three years of service).

Stock Options

The Company recorded the following compensation costs related to stock options for the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
		(in millions)	
Stock-based compensation cost related to stock options – general and administrative expense	**$ 5**	$ 5	$ 5
Stock-based compensation cost related to stock options – capitalized	**$ 3**	$ 4	$ 5

The Company also recorded a deferred tax asset of $2, $3 and $4 million related to stock options in 2015, 2014 and 2013, respectively. A total of $13 million of unrecognized compensation cost related to the Company's unvested stock options. 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 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	**2015**	2014	2013
Risk-free interest rate	**1.7%**	1.6%	1.5%
Expected dividend yield	**–**	–	–
Expected volatility	**36.0%**	32.5%	38.6%
Expected term	**5 years**	5 years	5 years

The following tables summarize stock option activity for the years 2015, 2014 and 2013 and provide information for options outstanding at December 31 of each year:

	2015		2014		2013	
	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	**3,622**	**$ 35.41**	3,313	$ 35.70	3,650	$ 29.84
Granted	**2,401**	**9.47**	835	32.31	571	38.95
Exercised	**–**	**–**	(402)	30.60	(833)	12.12
Forfeited or expired	**(400)**	**32.20**	(124)	37.80	(75)	37.31
Options outstanding at December 31	**5,623**	**$ 24.57**	3,622	$ 35.41	3,313	$ 35.70

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Options Outstanding at December 31, 2015	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Options Exercisable at December 31, 2015	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)
	(in thousands)			(in thousands)		
$7.74-$29.69	2,421	9.63	6.8	20	28.46	1.8
$30.59-$35.91	1,397	32.32	4.9	900	33.27	4.3
$36.22-$39.68	1,412	37.50	3.4	1,249	37.31	3.2
$40.15-$51.47	393	42.58	2.0	333	41.86	1.4
	5,623	$ 24.57	5.1	2,502	$ 36.39	3.4

The weighted-average grant-date fair value of options granted during the years 2015, 2014 and 2013 was $3.16, $10.16, and $13.39, respectively. There were no options exercised in 2015. The total intrinsic value of options exercised during 2014 and 2013 was $4 million and $22 million, respectively.

Restricted Stock

The Company recorded the following compensation costs related to restricted stock grants for the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
		(in millions)	
Stock-based compensation cost related to restricted stock grants – general and administrative expense	**$ 14**	$ 10	$ 7
Stock-based compensation cost related to restricted stock grants – capitalized	**$ 16**	$ 12	$ 7

The Company also recorded a deferred tax asset of $11 million related to restricted stock for the year ended December 31, 2015, compared to deferred tax liabilities of $10 million for 2014 and $15 million for 2013. As of December 31, 2015, there was $88 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 2015, 2014 and 2013 and provides information for restricted stock outstanding at December 31 of each year:

	2015		2014		2013	
	Number of Shares	**Weighted Average Grant Date Fair Value**	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value
	(in thousands)		(in thousands)		(in thousands)	
Unvested shares at January 1	**2,376**	**$ 34.00**	1,771	$ 37.55	1,118	$ 35.64
Granted	**5,822**	**8.07**	1,295	30.89	1,109	38.92
Vested	**(873)**	**33.33**	(548)	37.12	(382)	36.29
Forfeited	**(103)**	**29.14**	(142)	37.91	(74)	35.81
Unvested shares at December 31	**7,222**	**$ 13.24**	2,376	$ 34.00	1,771	$ 37.55

The fair values of the grants were $47 million for 2015, $40 million for 2014 and $43 million for 2013. The total fair value of shares vested were $29 million for 2015, $20 million for 2014 and $14 million for 2013.

Equity-Classified Performance Units

The Company recorded the following compensation costs related to equity-classified performance units for the years ended December 31, 2015. The performance units include a market condition based on Relative Total Shareholder Return ("TSR") and a performance condition based on the Company's Present Value Index ("PVI"), collectively the "Performance Measures." The fair value of the TSR market condition of the performance units is based on a Monte Carlo model and is amortized to compensation expense on a straight-line basis over the vesting period of the award. The fair value of the PVI performance condition of the performance units is based on economic analysis for each investment opportunity based upon the expected present value added for each dollar to be invested and amortized to compensation expense on a straight line basis over the vesting period of the award. The grant date fair value is calculated using the Performance Measures and the closing price of the Company's common stock at the grant date.

	2015		2014	
	(in millions)			
Stock-based compensation cost related to performance units - general and administrative expense	**$**	**6**	$	3
Stock-based compensation cost related to performance units - capitalized	**$**	**4**	$	2

The Company also recorded a deferred tax asset of $4 million related to equity-based performance units for the year ended December 31, 2015, compared to a deferred tax asset of $2 million in 2014 and no deferred tax recorded in 2013. As of December 31, 2015, there was $14 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 twelve months ended December 31, 2015 and provides information for unvested units as of December 31, 2015:

	2015			2014		
	Number of Units (1)	**Weighted Average Grant Date Fair Value**		Number of Units (1)	Weighted Average Grant Date Fair Value	
Unvested shares at January 1	223	$	40.44	–	$	–
Granted	443		35.22	359		40.44
Vested	(259)		37.46	(111)		40.44
Forfeited	–		–	(25)		40.44
Unvested shares at December 31	407	$	36.65	223	$	40.44

(1) These amounts reflect the number of performance units granted in thousands. The actual payout of shares may range from a minimum of zero shares to a maximum of two shares contingent upon the actual performance against the Performance Measures.

Liability-Classified Performance Units

Certain employees were provided performance units vesting equally over three years. The payout of these units is 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, is paid in cash. The Company paid $31 million related to the vested performance units in 2015, $25 million in 2014, and $3 million in 2013. As of December 31, 2015 and 2014, the Company's liability under the performance unit agreements was $8 million and $51 million, respectively.

(14) 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 Services 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 and other income (loss). The "Other" column includes items not related to the Company's reportable segments including real estate and corporate items.

	Exploration and Production	Midstream Services	Other	Total
		(in millions)		
2015				
Revenues from external customers	**$ 2,095**	**$ 1,038**	**$ –**	**$ 3,133**
Intersegment revenues	**(21)**	**2,081**	**–**	**2,060**
Operating income (loss)	**(7,104)** (2)	**583**	**(1)**	**(6,522)**
Other loss, net	**(21)**	**(9)**	**–**	**(30)**
Gain (loss) on derivatives	**51**	**–**	**(4)**	**47**
Depreciation, depletion and amortization expense	**1,028**	**62**	**1**	**1,091**
Impairment of natural gas and oil properties	**6,950**	**–**	**–**	**6,950**
Interest expense(1)	**47**	**9**	**–**	**56**
Provision (benefit) for income taxes(1)	**(2,273)**	**268**	**–**	**(2,005)**
Assets	**6,588** (3)	**1,290**	**232**	**8,110**
Capital investments(4)	**2,258**	**167**	**12**	**2,437**
2014				
Revenues from external customers	$ 2,850	$ 1,188	$ –	$ 4,038
Intersegment revenues	12	3,170	–	3,182
Operating income (loss)	1,013	361	(1)	1,373
Other loss, net	(3)	(1)	–	(4)
Gain (loss) on derivatives	142	(1)	(2)	139
Depreciation, depletion and amortization expense	884	58	–	942
Interest expense(1)	47	12	–	59
Provision for income taxes(1)	402	123	–	525
Assets	13,018 (3)	1,554	353	14,925
Capital investments(4)	7,254	144	49	7,447
2013				
Revenues from external customers	$ 2,398	$ 973	$ –	$ 3,371
Intersegment revenues	6	2,374	–	2,380
Operating income	879	325	–	1,204
Other income (loss), net	3	–	(1)	2
Gain on derivatives	26	–	–	26
Depreciation, depletion and amortization expense	735	51	1	787
Interest expense(1)	30	11	1	42
Provision (benefit) for income taxes(1)	368	119	(1)	486
Assets	6,357 (3)	1,427	264	8,048
Capital investments(4)	2,052	158	25	2,235

(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 $6,950 million from non-cash impairments of natural gas and oil properties.
(3) Includes office, technology, drilling rigs and other ancillary equipment not directly related to natural gas and oil property acquisition, exploration and development activities.
(4) Capital investments include a decrease of $33 million for 2015, an increase of $155 million for 2014 and a decrease of $25 million for 2013 related to the change in accrued expenditures between years.

Included in intersegment revenues of the Midstream Services segment are approximately $1.8 billion, $2.8 billion and $2.0 billion for 2015, 2014 and 2013, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures, prepaid debt and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments. For 2015, 2014, and 2013, capital investments within the E&P segment include $4 million, $11 million, and $35 respectively, related to the Company's activities in Canada. As of December 31, 2015, 2014, and 2013, E&P assets include $50 million, $77 million, $79 million related to the Company's activities in Canada.

(15) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2015 and 2014:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(in millions, except per share amounts)			
	2015			
Operating revenues	**$ 933**	**$ 764**	**$ 749**	**$ 687**
Operating income (loss) [(1)]	**165**	**(1,284)**	**(2,842)**	**(2,561)**
Net income (loss) attributable to common stock [(2)]	**46**	**(815)**	**(1,766)**	**(2,134)**
Earnings per share - Basic	**0.12**	**(2.13)**	**(4.62)**	**(5.58)**
Earnings per share - Diluted	**0.12**	**(2.13)**	**(4.62)**	**(5.58)**
	2014			
Operating revenues	$ 1,113	$ 1,035	$ 928	$ 962
Operating income	435	367	286	285
Net income	194	207	211	312
Earnings per share - Basic	0.55	0.59	0.60	0.89
Earnings per share - Diluted	0.55	0.59	0.60	0.88

(1) The operating losses for the second, third and fourth quarters of 2015 included full cost non-cash impairments of natural gas and oil properties of $1.5 billion, $2.8 billion and $2.6 billion, respectively.

(2) Net income attributable to common stock was reduced by $7 million in the first quarter of 2015 to recognize the portion of the Company's net income that would be distributed to the holders of preferred securities (mandatory convertible preferred stock) at year-end. However, as a result of the Company's net loss in the second quarter that persisted for the year ended December 31, 2015, participating securities were ultimately not entitled to receive a distribution.

(16) SUBSEQUENT EVENTS

As of January 6, 2016, the Company accepted the resignation of Steven L. Mueller as Chief Executive Officer ("CEO") of the Company and appointed William J. Way as CEO. Mr. Way will continue as President and was elected as a director of the Company as of January 6, 2016. Mr. Mueller will continue as a non-officer employee of the Company and as a director and non-executive Chairman of the Board of Directors of the Company through May 17, 2016, the date scheduled for the next annual meeting of stockholders and will not stand for re-election.

On January 21, 2016, the Company notified employees of a workforce reduction plan. Affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, amendments to outstanding equity awards that modified forfeiture provisions on separation from the Company. Some affected employees were offered the opportunity to accept reduced roles with the Company. The Company expects the plan to be substantially implemented by the end of the first quarter of 2016.

The Company expects to record a pre-tax charge to earnings in the first quarter of 2016 ranging from approximately $60 to $70 million, including the following:

- one-time cash severance payments and payment of taxes totaling approximately $45 to $50 million, and
- costs associated with the elimination of service requirements for equity awards to certain terminated employees of approximately $15 to $20 million.

Each range of charges is an estimate. The actual charge may vary based on various factors, including the number of affected employees who accept different jobs with the Company.

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 management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of 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, 2015 at a reasonable assurance level.

As of December 31, 2015, management has included the natural gas and oil assets acquired in 2014 from a subsidiary of Chesapeake Energy Corporation in West Virginia and southwest Pennsylvania ("Chesapeake Property Acquisition") in our assessment of the effectiveness of our internal control over financial reporting.

There were no changes in our internal controls 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, 2015, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Management's Report on Internal Control Over Financial Reporting is included on page 64 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 65 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, 2015, that was not reported on such form.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Name	Officer Position	Age(1)	Years Served as Officer
Steven L. Mueller	Chairman of the Board	62	7
William J. Way	President and Chief Executive Officer	56	4
Mark K. Boling	Executive Vice President and President V+ Development Solutions	58	14
Jeffrey B. Sherrick	Executive Vice President – Corporate Development	61	7
R. Craig Owen	Senior Vice President and Chief Financial Officer	46	7
John C. Ale	Senior Vice President, General Counsel and Secretary	61	2

(1) As of February 23, 2016

Mr. Mueller was appointed Chairman of the Board in May 2014. Mr. Mueller previously served as Chief Executive Officer from May 2009 to January 2016, having joined the Company as President and Chief Operating Officer in 2008.

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. Boling was appointed Executive Vice President and President, V+ Development Solutions in December 2012. Prior to that, he served as Senior Vice President, General Counsel and Secretary since January 2002.

Mr. Sherrick was appointed Executive Vice President – Corporate Development in December 2013. Prior to that, he served as Senior Vice President, U.S. Exploitation of the Company's subsidiaries SEECO, Inc. and Southwestern Energy Production Company since 2008.

Mr. Owen was appointed Senior Vice President in May 2012 and Chief Financial Officer in October 2012. Prior to October 2012, he served as Controller since 2008.

Mr. Ale was appointed Senior Vice President, General Counsel and Secretary in November 2013. Prior to that, Mr. Ale 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.

The Company's officers are elected each year at the first meeting of the Board of Directors following the annual meeting of stockholders, the next of which is expected to occur on May 17, 2016, and hold office until their successors are duly elected and qualified. There are no family relationships between any of the Company's directors or executive officers.

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 17, 2016 (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 2016 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.

Southwestern Energy 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. The full text of such code of ethics has been posted on the Company's website at www.swn.com, and 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.

ITEM 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2016 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2016, 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 2016 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2016, 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 2016 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2016, 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 2016 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2016, and is incorporated herein by reference.*

* Except for information or data specifically incorporated by reference under Items 10 through 14, other information in our 2016 Proxy Statement are 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 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.

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: February 25, 2016	By: /s/ R. CRAIG OWEN
	R. Craig Owen
	Senior Vice President
	and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 25, 2016, on behalf of the Registrant below by the following officers and by a majority of the directors.

/s/ STEVEN L. MUELLER Steven L. Mueller	Director and Chairman of the Board
/s/ WILLIAM J. WAY William J. Way	Director, President and Chief Executive Officer (Principal executive officer)
/s/ R. CRAIG OWEN R. Craig Owen	Senior Vice President and Chief Financial Officer (Principal financial officer)
/s/ JOSH C. ANDERS Josh C. Anders	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/ VELLO A. KUUSKRAA Vello A. Kuuskraa	Director
/s/ KENNETH R. MOURTON Kenneth R. Mourton	Director
/s/ ELLIOTT PEW Elliott Pew	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)
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 November 9, 2015. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed November 13, 2015)
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	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)
4.3	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)
4.4	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)
4.5	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)
4.6	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)
4.7	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)
4.8	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)
4.9	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)

4.10	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)
4.11	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)
4.12	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)
4.13	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)
4.14	Commitment Letter dated October 14, 2014 between Southwestern Energy Company, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Bank of America, N.A. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on October 17, 2014)
4.15	Bridge Term Loan Credit Agreement, dated December 19, 2014, among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, Citibank, N.A., JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and The Royal Bank of Scotland plc, as Co-Syndication Agents, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Sole Lead Arranger and Sole Bookrunner, and the lenders 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 December 23, 2014)
4.16	Term Loan Credit Agreement, dated December 19, 2014, among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Sole Lead Arranger and Sole Bookrunner, 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 December 23, 2014)
4.17	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)
4.18	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)
4.19	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)
4.20	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)
4.21	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)
4.22	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)
4.23	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)
4.24	Form of 4.095% 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)

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, 2012)
10.5	Southwestern Energy Company Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.2(b) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.6	Amendment to Southwestern Energy Company Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.5 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008)
10.7	Second Amendment to Southwestern Energy Company Incentive Compensation Plan (Incorporated by reference to Exhibit 10.6 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 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)
10.9	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)
10.10	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)
10.11	Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2000 Annual Meeting of Stockholders)
10.12	Southwestern Energy Company 2002 Employee Stock Incentive Plan, effective October 23, 2002. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.13	Southwestern Energy Company 2002 Performance Unit Plan, as amended, effective December 8, 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2012)
10.14	Southwestern Energy Company 2004 Stock Incentive Plan. (Incorporated by reference to Appendix A to the Registrant's Proxy Statement dated March 29, 2004)
10.15	Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Annex A of the Registrant's Proxy Statement filed April 8, 2013)
10.16*	Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement.
10.17	Southwestern Energy Company 2013 Incentive Plan Guidelines for Annual Incentive Awards. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.18	Southwestern Energy Company 2013 Incentive Plan Form of Incentive Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.4 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 Non-Qualified Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.20	Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement for Directors. (Incorporated by reference to Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.21	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement. (Incorporated by reference to Exhibit 10.7 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.22	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement for Directors. (Incorporated by reference to Exhibit 10.8 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.23	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement. (Incorporated by reference to Exhibit 10.9 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.24	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)
10.25	Form of Incentive Stock Option Agreement for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 20, 2004)
10.26	Form of Non-Qualified Stock Option Agreement for non-employee directors for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on December 20, 2004)
10.27	Form of Incentive Stock Option for awards granted on or after December 8, 2005. (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.28	Form of Restricted Stock Agreement for awards granted on or after December 8, 2005. (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.29	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)
10.30	Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 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, 2012)
10.31	Master Lease Agreement by and between Southwestern Energy Company and SunTrust Leasing Corporation dated December 29, 2006. (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, 2006)
10.32	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)
10.33	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, 2008)
10.34	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)
10.35	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)

10.36	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)
10.37	Term Loan Credit Agreement, dated November 17, 2015, among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Lead Arranger and Bookrunner, and the lenders from time to time party thereto. (Incorporated by reference to the Registrant's Current Report on Form 8-K filed November 17, 2015)
10.38*	Retirement Agreement dated January 11, 2016 between Southwestern Energy Company and Steven L. Mueller.
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 January 15, 2016
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