Energy for Our World, Enhancing Our Future

Southwestern Energy Company
2016 Annual Report

We have featured the Formula on the cover as 2016 was indeed a year of adjusting to market dynamics.

As a company we have responded quickly and decisively to the challenging commodity price environment. We have realigned our Company and recalibrated our strategy with a steadfast focus on creating Value+ for our shareholders.

SWN's formula reflects our values and clarifies our priorities.

It was developed by company leaders years ago as a guiding light defining how SWN will conduct its business.

The arrow denoting value creation was originally drawn as a straight line arrow angling up.

But one leader thoughtfully insisted it be redrawn as a jagged arrow, recognizing that business conditions do not always let you follow a straight line to long-term value creation and, instead, course corrections may be necessary.

$\frac{R^2}{A} \rightarrow V^{+}$®

The Right People doing the Right Things, wisely investing the cash flow from the underlying Assets will create Value+®

Dear Fellow Shareholders

The bold and decisive actions we took in 2016 have built strong momentum to tackle market challenges and capture the opportunities ahead, and we are delivering remarkable results. With the gains we made in 2016, we are creating long-term sustainable value, as evidenced by our return to value-added growth.

Financial Discipline

Financial discipline is a core principle in the fabric of SWN. Throughout 2016, we took actions that strengthened the balance sheet and increased our liquidity. Through the combination of extending bank agreements, successfully issuing equity, launching and concluding tender offers for debt and completing the sale of long-dated inventory, we reduced net debt by $1.5 billion and our remaining 2017 and 2018 debt maturities to $316 million. Based on the recent 2017 strip, we anticipate continued improvement to the balance sheet and expect net debt to EBITDA at year-end 2017 to be below 3.0. We are continuing to proactively look for opportunities to further de-lever and strengthen the balance sheet.

Strategy Execution

Delivering value to shareholders is at the core of our forward strategy and plan. Our employees are aggressively executing our strategy with the goal of powering SWN to industry-leading financial and operational performance. Our continued drive to expand margins is unyielding. In 2016, we reduced costs by more than $200 million with the majority of these savings structural and sustainable. As an example, we successfully renegotiated gathering and processing contracts in Southwest Appalachia, which reduced lease operating costs, and created a solution for our dry gas gathering needs for our northern acreage. Enterprising employees are testing several promising technical and operating methods to improve well productivity. The initial results are encouraging and we look forward to sharing more on our progress throughout the year as we have more definitive information to report.

Two overarching principles of our strategy are that we will invest within cash flow and be disciplined in capital allocation. This capital discipline differentiates us from many in the industry and will continue to do so moving forward. It is designed deliberately to result in greater assurance of realizing expected returns while mitigating some of the risk associated with commodity prices.

Operations Overview

We are leveraging our operational expertise as a competitive advantage. We entered 2017 with strong momentum propelled by the success from the resumption of drilling and completion activities. We took advantage of the pause in activity during 2016 to drive greater operational efficiency and technological advances. Each of our core asset areas is intensely focused on finding innovative ways to reduce costs and increase value-added production. We are seeing strong results!

We have a robust, well-balanced portfolio of large-scale, high-quality, long-lived assets that continues to provide steady production through the near, medium and long term, with an abundance of exciting growth opportunities. This balance gives us flexibility and optionality to ramp up or ramp down accordingly to operate profitably under various price scenarios.

Our Fayetteville asset has vast reserves and generates a strong stream of cash flow. We have challenged ourselves to bring down our breakeven costs to compete for capital with the Appalachia locations in alignment with our disciplined investment approach. We are currently in the early delineation phase of testing the Moorefield formation and our initial results are encouraging.

Our Northeast Appalachia asset offers the advantageous combination of world-class E&P acreage and strategic and highly profitable transportation capacity options. Our increased well productivity here is driving long-term value. Early on, SWN recognized the strategic importance of buying firm transportation to maximize the value of our world-class Northeast Appalachia E&P assets. We were able to build a takeaway portfolio with access to many diversified markets which gives us the ability to capture incremental value. This is a distinct competitive advantage. As a first mover, we were able to strategically purchase capacity at very competitive rates and build renewal and extension options into our contracts. This has resulted in greater flexibility, lower costs and less risk, while minimizing our exposure to long-term ("take or pay") commitments.

Our Southwest Appalachia asset has premier rock quality and offers the opportunity to drill both wet and dry gas wells, which we will optimize to capture the best commodity prices. The scale and diversity of this asset allows the Company to shift capital to maximize returns in any commodity price environment. With abundant resource potential, these assets will generate significant value-adding growth that will drive the Company in the long run.

> **"We have met the challenge to re-invent ourselves, and we have taken dramatic steps to strengthen our balance sheet and expand margins to prosper even in an extended period of lower prices."**

Core Value Focus

Along with our operational achievements, I am also very proud of our 2016 safety and environmental performance. We took extra time and precautions to ensure our workforce resumed drilling and completion activity in a safe manner. Our culture is one built on safety as a core value and our results in 2016 demonstrate that commitment. We improved our metrics and will strive to continue that trend in 2017.

Additionally, we strive to be good environmental stewards and respected members of the community. In 2016, we achieved our goal of being fresh water neutral, whereby we replace more fresh water than we use in our operation through treating or conservation projects that include restoring fresh water sources that had become compromised by others. And we continue to reduce our own methane emission levels and work on programs to reduce emissions throughout the vertical natural gas chain. These are but two examples of our industry-leading environmental efforts to identify and implement innovative solutions to minimize environmental and community impacts of our activities.

Looking forward

With commodity prices headlining 2016 financial news, it is easy to lose sight of one of the greatest success stories of the 21st Century—the incredible transformation of the U.S. energy market. Today, the U.S. is the world's largest producer of natural gas, a triumph that was inconceivable just a decade ago. This transformation has brought us close to the goal of American energy independence. It has sparked a resurgence in U.S. manufacturing, bringing back jobs and prosperity and improving the lives of Americans. As the third largest U.S. gas producer, it is a privilege and a responsibility to be an integral part of America's energy success story.

While a lower price environment is not without its challenges, we have taken dramatic steps to strengthen our balance sheet and re-invent ourselves to prosper even in an extended period of low prices. At the same time, we are prepared to move quickly to take advantage of price recovery.

SWN is ideally positioned to tap our abundant, high-quality resources to meet the nation's demand for reliable, affordable clean energy. Clean-burning natural gas will continue to be the world's essential lower-carbon energy supply well into the future. SWN is proud of our role as an industry leader in safe, responsible resource development and confident in our ability to deliver top-quartile growth in shareholder value.

Thank you for your support.

Sincerely,

William J. Way, President & Chief Executive Officer

Financial Highlights

Average Realized Gas Price ($/Mcf)

'16	$ 1.64
'15	$ 2.37
'14	$ 3.72
'13	$ 3.65
'12	$ 3.44

Net Cash Provided by Operating Activities (in Millions)

'16	$ 498
'15	$ 1,580
'14	$ 2,335
'13	$ 1,909
'12	$ 1,654

Capital Investments (in Millions)(1)

'16	$ 648
'15	$ 2,437
'14	$ 7,447
'13	$ 2,235
'12	$ 2,081

Diluted (Loss) Earnings Per Share

'16	$ (6.32)
'15	$ (12.25)
'14	$ 2.62
'13	$ 2.00
'12	$ (2.03)

Adjusted Diluted (Loss) Earnings Per Share(2)

'16	$ (0.01)
'15	$ 0.19
'14	$ 2.27
'13	$ 2.00
'12	$ 1.39

Adjusted EBITDA (in Millions)(2)

'16	$ 686
'15	$ 1,440
'14	$ 2,320
'13	$ 1,998
'12	$ 1,638

Production (Bcfe)

'16	875
'15	976
'14	768
'13	657
'12	565

Reserves (Bcfe)

'16	5,253
'15	6,215
'14	10,747
'13	6,976
'12	4,018

Production Costs ($/Mcfe)(3)

'16	$ 0.97
'15	$ 1.02
'14	$ 1.02
'13	$ 0.96
'12	$ 0.89

Footnotes **(1)** Includes acquisition costs and post-closing adjustments for the Appalachia transactions that closed in December 2014 and January 2015 of $609 million in 2015 and $5,007 million in 2014. **(2)** For the Company's reconciliation of adjusted diluted (loss) earnings per share and adjusted EBITDA to Generally Accepted Accounting Principles, see "Non-GAAP Reconciliations" on the inside back cover. **(3)** Production cost per Mcfe includes lease operating expenses and production taxes. **(4)** Proved developed finding and development cost are computed by dividing exploration and development capital costs incurred, excluding capitalized interest and expenses by PDP reserve additions and proved undeveloped conversions.

2016 Proved Developed Finding & Development Cost

$0.75/Mcfe(4)

Financial Strength

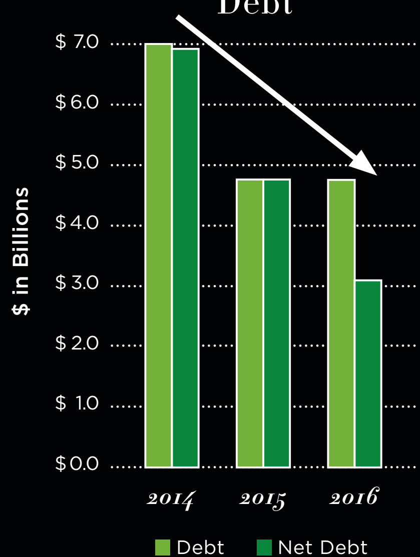
We are committed to rigorously managing our balance sheet and risks.

We budget to invest only from our net cash flow, protect our projected cash flows through hedging, and continue to ensure strong liquidity while de-levering the Company. Our capital budgets in 2016 and 2017 were supplemented by $500 million from our $1.2 billion equity offering in 2016.

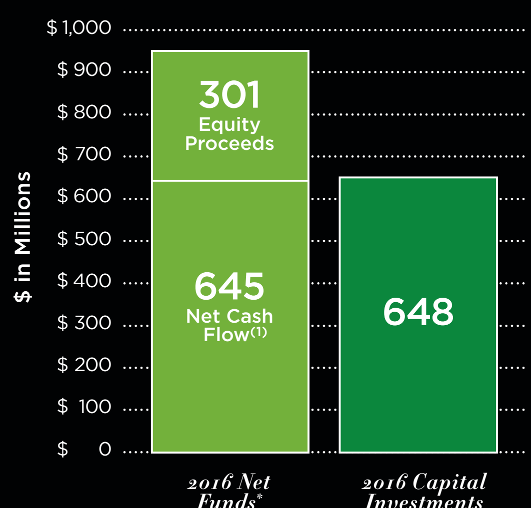
In 2016, we rearranged and extended our bank credit facilities, successfully tendered for approximately $700 million of our near-term senior notes, and divested of long-dated acreage. These activities reduced total debt to $4.7 billion and net debt to $3.2 billion, with only $316 million remaining of outstanding debt maturities through 2018. Additionally, we initiated a rolling 3-year hedge program designed to provide protection of cash flows and ensure targeted returns utilizing a combination of commodity and basis hedges.

As of December 31, 2016, we had approximately 560 Bcf of our 2017 gas production hedged at a floor price of $3.02, 240 Bcf of our 2018 gas production hedged at a floor price of $2.97 and 62 Bcf of our 2019 gas production hedged at a floor price of $2.92.

Debt



Invest within Cash Flow



(1) For the reconciliation of net cash flow to Generally Accepted Accounting Principles, see "Non-GAAP Reconciliations" on the inside back cover

*Net Funds is the sum of Net Cash Flow and the amount of proceeds from the 2016 equity offering utilized for capital investments

Margin Expansion

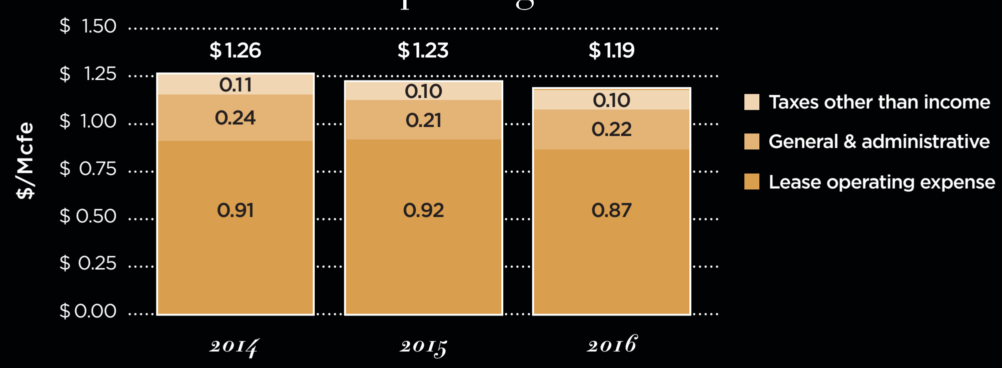
Margin expansion is a key focus at Southwestern, both through cost reductions and revenue enhancements.

We apply strong technical, operational, commercial and marketing skills to improve the productivity of our wells, reduce cost, and pursue commercial arrangements that extract greater value from each of our assets.

We believe our demonstrated ability to improve margins, especially by levering the scale of our large assets, gives us a competitive advantage as we move into the future.

In 2016, great strides were made in our efforts to enhance margins. For example, we executed production enhancement initiatives, such as compression optimization, that resulted in over 30 Bcfe of production from lower base production declines. Additionally, we finalized a new gathering agreement in Southwest Appalachia that was estimated to reduce costs by over $35 million, with future savings realized with increased production levels. As a company, lease operating expenses were reduced by $0.05 per Mcfe, or 5% in 2016. Margin enhancement is a key component of our strategy and will remain a focus as we move throughout 2017 and beyond.

E&P Cash Operating Costs




Tax Deferred

The Hydrocarbon Value Chain

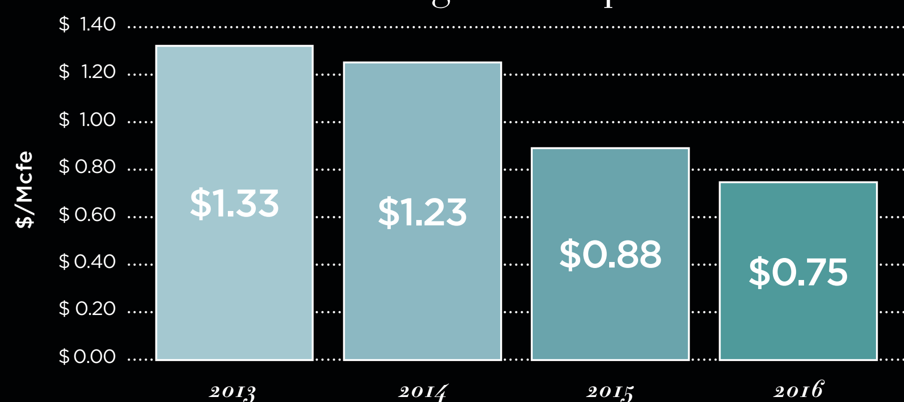
We often expand our activities vertically when we believe this will enhance our margins or otherwise provide us competitive advantages.

For example, the Company developed and operates one of the largest contiguous gathering systems in the United States. As of December 31, 2016, we gathered 1.5 Bcf per day of gas volumes and had approximately 2,045 miles of pipe from the individual wellheads to the transmission lines.

We also operate drilling rigs, which we custom built to maximize operational efficiencies throughout our assets. These drilling rigs continue to deliver extraordinary results, both in drilling time and drilling accuracy, and are a key component of the improved well productivity exhibited in each of our operating areas. We also own a sand mine that provides proppant in hydraulic fracturing in the Fayetteville area.

As a result, we are able to keep costs low while testing various proppant amounts used in completions, potentially unlocking significant additional value from that asset. Additionally, we own two pressure pumping spreads that we operated until early 2016 and that are available to be put back into service should service costs rise from their current levels. Combined, our vertical integration activities help protect and expand margins, minimize the risk of unavailability of these services from third parties, diversify our cash flows and capture additional value.

PDP Finding & Development Cost




swn
Southwestern Energy
swn
Southwestern Energy
Tracy

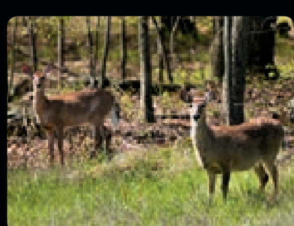
Innovative Environmental Solutions and Policy Formation

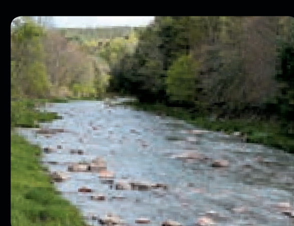
Our Company is a leader in identifying and implementing innovative solutions to unconventional hydrocarbon development to minimize the environmental and community impacts of our activities.

We work extensively with governmental, non-governmental and industry stakeholders to develop responsible and cost-effective programs. We demonstrate that a company can operate responsibly and profitably, putting us in a better position not only to comply with new regulations, but also to work with regulators to demonstrate effective methods for dealing with important concerns.

Through our ECH_2O (Energy Conserving Water) initiative we pursue the offset of our freshwater use including innovative water management practices and conservation projects. During 2016, we accomplished our goal of becoming fresh water neutral in each of our operating areas. That is, for every gallon of fresh water we use, we aim to offset or replenish that gallon through water quality improvement projects or treatment technologies that return fresh water to the environment.

The performance based approach of Our Nation's Energy (ONE) Future was recognized by the EPA in 2016 and accepted as part of the EPA Methane Challenge. The ONE Future coalition is a group of eight companies, co-founded by SWN, dedicated to reducing methane emissions across the natural gas value chain. ONE Future seeks to reduce emissions to an average annual leak/loss rate of no more than 1 percent of gross U.S. natural gas production by 2025. (The EPA's 2012 National Greenhouse Gas Inventory estimated the industry's leak/loss rate at 1.3 percent.) In 2015, SWN reported a methane leak loss rate of 0.18% of production, a rate well below our ONE Future target.

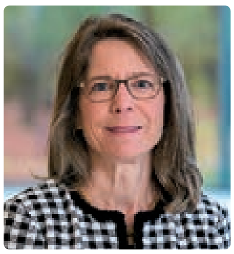




Executive Officers

From left to right: **R. Craig Owen (8),** Senior Vice President and Chief Financial Officer; **James W. Vick (5),** Senior Vice President - Business Information Services; **John E. "Jack" Bergeron, Jr. (9),** Senior Vice President - Operations; **John C. Ale (3),** Senior Vice President, General Counsel and Secretary; **Randy L. Curry (2),** Senior Vice President - Midstream; **William J. Way (5),** President and Chief Executive Officer; **C. Greg Stoute (11),** Vice President - Health, Safety and Environmental, and Regulatory; **Jennifer N. McCauley (7),** Senior Vice President - Administration; **Paul W. Geiger (2),** Senior Vice President - Corporate Development; **Mark K. Boling (15),** President - V+ Development Solutions

Directors

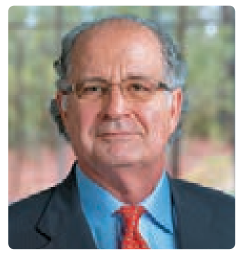


Catherine A. Kehr (5)
Retired – The Capital Group Companies

William J. Way (1)
President and Chief Executive Officer

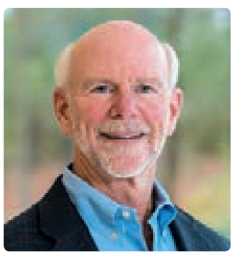
John D. Gass (4)
Retired - Chevron Corporation

Greg D. Kerley (6)
Retired - Southwestern Energy Company



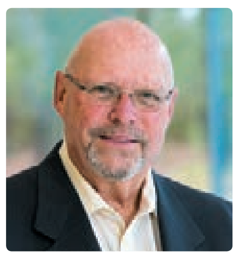
Jon A. Marshall (*)
Retired - Transocean Ltd.

Kenneth R. Mourton (22)
Managing Partner - Ball and Mourton, Ltd., PLLC



Terry W. Rathert (2)
Retired - Newfield Exploration Company

Elliott Pew (4)
Retired - Common Resources



Alan H. Stevens (6)
Retired - Southwestern Energy Company

Corporate Officers

William J. Way (5)
President and Chief Executive Officer

Mark K. Boling (15)
President–V+ Development Solutions

R. Craig Owen (8)
Senior Vice President and Chief Financial Officer

John C. Ale (3)
Senior Vice President, General Counsel and Secretary

Jennifer N. McCauley (7)
Senior Vice President–Administration

James W. Vick (5)
Senior Vice President–Business Information Services

Mark L. Colassaco (4)
Vice President–Business Information Services

Colin P. O'Beirne (6)
Vice President and Controller

Jennifer E. Stewart (6)
Senior Vice President–Tax and Treasury

Randall L. Barron (14)
Vice President–Treasury

Sarah E. Battisti (2)
Vice President–Government and Community Relations

Danny W. Ferguson (12)
Vice President–Government and Community Relations

Roy D. Hartstein (9)
Vice President–Strategic Solutions

John C. Gargani (23)
Vice President–Human Resources

Operating Subsidiary Officers

Jim R. Dewbre (19)
Senior Vice President–Land

John E. "Jack" Bergeron, Jr. (9)
Senior Vice President–Operations

Paul W. Geiger (2)
Senior Vice President–Corporate Development

Ron E. Hyden (3)
Vice President–Technology

Douglas H. Van Slambrouck (17)
Senior Vice President–Fayetteville Shale Division

Randy L. Curry (2)
Senior Vice President–Midstream

C. Greg Stoute (11)
Vice President–Health, Safety and Environmental, and Regulatory

David A. Dell'Osso (11)
Vice President–Northeast Appalachia Division

Derek W. Cutright (8)
Vice President–Southwest Appalachia Division

Harry H. "Sonny" Bryan (16)
Vice President–Drilling and Completions

Stephen M. Guidry (9)
Vice President–Land, Southwest Appalachia Division

John R. Lee III (7)
Vice President–Midstream Field Operations

R. Jason Kurtz (19)
Vice President–Marketing and Transportation

For Executive Officers, years with the Company are shown on this page in parentheses.

For Directors, years served on the Board of Directors are shown on this page in parentheses, and an asterisk (*) indicates less than one year of service.

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, 2016**

Commission file number **001-08246**

Southwestern Energy Company

(Exact name of registrant as specified in its charter)

Delaware	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
10000 Energy Drive, Spring, Texas	**77389**
(Address of principal executive offices)	(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 $4,913,492,123 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2016 of $12.58. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 21, 2017, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 497,953,968.

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 23, 2017 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, 2016

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

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

ITEM 1. BUSINESS

Southwestern Energy Company (including its subsidiaries, collectively, "we", "Southwestern" or the "Company") is an independent natural gas and oil company engaged in development and production activities, including related natural gas gathering and marketing. Southwestern is a holding company whose assets consist of direct and indirect ownership interests in, and whose business is conducted substantially through, its subsidiaries. Currently we operate only in the United States. 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

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

$$\frac{R^2}{A} \rightsquigarrow V^{+}\text{®}$$

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

In applying these core principles, we concentrate on:

- *Financial Strength*. We are committed to rigorously managing our balance sheet and risks. We budget to invest only from our net cash flow (along with the remaining portion of proceeds from our equity issuance in 2016 that we previously earmarked for capital investment), protect our projected cash flows through hedging, and continue to ensure strong liquidity while de-levering the Company.
- *Increasing Margins*. We apply strong technical, operational, commercial and marketing skills to reduce cost, improve the productivity of our wells and pursue commercial arrangements that extract greater value from them. We believe our demonstrated ability to improve margins, especially by levering the scale of our large assets, gives us a competitive advantage as we move into the future.
- *Dynamic Management of Assets Throughout Life Cycle.* We own large-scale, long-life assets in various phases of development. In early stages, we ramp up development through technical, operational and commercial skills, and as they grow we look for ways to maximize their value, through efficient operating practices along with commercial and marketing expertise.
- *Deepening Our Inventory*. We continue to expand the inventory of properties that we can develop profitably by converting our extensive resources into proved reserves, targeting additions whose productivity largely has been demonstrated and improving efficiencies in production.
- *The Hydrocarbon Value Chain*. We often expand our activities vertically when we believe this will enhance our margins or otherwise provide us competitive advantages. For example, the Company developed and operates the largest gathering system in the Fayetteville Shale area. We operate drilling rigs and own a sand mine that provides a low cost proppant in hydraulic fracturing. These activities help protect our margin, minimize the risk of unavailability of these resources from third parties, diversify our cash flows and capture additional value.
- *The Next Chapter of Unconventionals.* Our company grew dramatically in the 2000s by harnessing and enhancing the newfound combination of hydraulic fracturing and horizontal drilling technologies. Our people constantly search for the next revolutionary technology and other operational advancements to capture greater value in unconventional hydrocarbon resource development. These developments – whether single, step-changing technologies or a combination of several incremental ones – can reduce finding and development costs and thus increase our margins.

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

During 2016, we executed on our business strategy by:

- Investing within our cash flow plus a portion of the proceeds from our successful equity offering earmarked for this purpose, with the remainder to debt reduction
- Investing in only those projects that meet our rigorous economic hurdles at strip pricing
- Rearranging and extending our bank credit facilities and successfully tendering for approximately $700 million of near-term senior notes, which enhanced and stabilized our liquidity and eliminated the overhang of near-term debt maturities
- Generating cash flow from operations of about $500 million, which reflects the impact of an aggressive assault on costs and improved drilling and completion performance
- Intelligently managing our portfolio, including disposing of acreage we were not planning to develop until well into the next decade and using the over $400 million of proceeds to reduce debt

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

Exploration and Production – Our largest business is the exploration for and production of natural gas, oil and NGLs, 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, oil and NGL 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 have smaller holdings in Colorado and Louisiana along with other areas in which we are testing potential new resources, including New Brunswick, Canada whose development is subject to a moratorium. We also have drilling rigs located in Pennsylvania, West Virginia and Arkansas and provide oilfield products and services, principally serving our 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 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 cash flow from operations has been derived from our E&P business. In 2016 and 2015, depressed commodity prices significantly decreased our E&P results. In 2016, our E&P segment generated cash flow from operations of $297 million, which constituted 60% of our total cash flow from operations. This compares to E&P-generated cash flow from operations of $1.1 billion and $2.1 billion in 2015 and 2014, respectively. Our E&P segment constituted 71% and 89% of our total cash flow from operations in 2015 and 2014, respectively. The remainder of our consolidated cash flow from operations in each of these years was primarily generated from our Midstream Services segment.

Exploration and Production

Overview

Operations in our E&P segment are primarily in the Appalachian Basin and Arkansas. We also are conducting activities in other basins targeting various formations as potential new resources.

Our E&P segment recorded operating losses of $2.4 billion and $7.1 billion in 2016 and 2015, respectively, and operating income of $1.0 billion in 2014. The operating losses in 2016 and 2015 were primarily the result of $2.3 billion, or $1.4 billion net of taxes, and $7.0 billion, or $4.3 billion net of taxes, respectively, of non-cash impairments of natural gas and oil properties due to decreased commodity prices. In May 2015, we divested of our East Texas and Arkoma properties, previously referred to as the Ark-La-Tex division.

Cash flow from operations from our E&P segment was $297 million in 2016, compared to $1.1 billion in 2015 and $2.1 billion in 2014. Our cash flow from operations decreased in 2016 as the effects of lower realized natural gas prices and decreased natural gas production more than offset our reduction in operating expenses. Our cash flow from operations 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.

Oilfield Services Vertical Integration

We provide some oilfield services that are strategic and economically beneficial for our E&P operations when our E&P activity levels and market pricing support these activities and we can do so more efficiently or cost-effectively. This vertical integration lowers our net well costs, allows us to operate efficiently and helps us to mitigate certain operational environmental risks. Among others, these services have included drilling, hydraulic fracturing and the mining of sand used as proppant for certain of our well completions in the Fayetteville Shale from a 570-acre complex in Arkansas.

We have conducted drilling operations for a majority of our operated wells. As of December 31, 2016, we had a total of five rigs drilling in Pennsylvania, West Virginia and Arkansas. In 2016, we provided drilling services for all of the wells that we operate in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale. Our drilling and completion services, along with our sand mine servicing our operated wells in the Fayetteville Shale, were inactive during our suspension of drilling and completion activities in the first half of 2016, but resumed, in part, as these activities were reinitiated during the third quarter of 2016.

We ceased providing hydraulic fracturing services in early 2016 at the same time as we suspended drilling and completion activities. To date, we have not resumed the provision of hydraulic fracturing services ourselves and instead are utilizing third parties who are offering lower costs. This may change as industry activity resumes, should that lead to higher prices or lower dependability from third-party providers of these services.

Our Proved Reserves

Our estimated proved natural gas, oil and NGL reserves were 5,253 Bcfe at year-end 2016, compared to 6,215 Bcfe at year-end 2015 and 10,747 Bcfe at year-end 2014. The decrease in our reserves in 2016 was primarily due to our production in 2016 and downward price revisions associated with decreased commodity prices, partially offset by upward performance revisions in Northeast Appalachia, Southwest Appalachia and the Fayetteville Shale. 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 and our production, 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, oil and NGL 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, oil and NGL reserves as of December 31, 2016, we utilized average prices from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.48 per MMBtu for natural gas, West Texas Intermediate oil of $39.25 per barrel for oil and $6.74 per barrel for NGLs, compared to $2.59 per MMBtu for natural gas, $46.79 per barrel for oil and $6.82 per barrel for NGLs at December 31, 2015 and $4.35 per MMBtu for natural gas, $91.48 per barrel for oil and $23.79 per barrel for NGLs at December 31, 2014.

Our after-tax PV-10 was $1.7 billion at year-end 2016, $2.4 billion at year-end 2015 and $7.5 billion at year-end 2014. The decrease in our after-tax PV-10 value in 2016 compared to 2015 was primarily due to lower reserve levels. The decrease in 2015 compared to 2014 was primarily due to comparatively lower average commodity prices. The difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2016 Proved Reserves by Category and Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows. Our year-end 2016 estimated proved reserves had a present value of estimated future net cash flows before income tax, or pre-tax PV-10, of $1.7 billion, compared to $2.4 billion at year-end 2015 and $9.5 billion at year-end 2014. Our year-end 2016 and 2015 after-tax PV-10 computations do not have future income taxes because our tax basis in the associated oil and gas properties exceeded expected pre-tax cash inflows, and thus do not differ from the pre-tax values.

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

At year-end 2016, 93% of our estimated proved reserves were natural gas and 99% of total estimated proved reserves were classified as proved developed, compared to 95% and 93%, respectively, in 2015 and 91% and 55%, respectively in 2014. 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 6.0 years at year-end 2016. In 2016, natural gas sales accounted for 89% of total operating revenues, compared to 93% and nearly 100% in 2015 and 2014, respectively.

The following table provides an overall and categorical summary of our natural gas, oil and NGL reserves, as of fiscal year-end 2016 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2016, and sets forth 2016 annual information related to production and capital investments for each of our operating areas:

2016 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	Appalachia				
	Northeast	Southwest	Fayetteville Shale	Other [1]	**Total**
Estimated Proved Reserves:					
Natural Gas (Bcf):					
Developed (Bcf)	1,540	293	2,954	2	**4,789**
Undeveloped (Bcf)	34	–	43	–	**77**
	1,574	293	2,997	2	**4,866**
Crude Oil (MMBbls):					
Developed (MMBbls)	–	10.2	–	0.3	**10.5**
Undeveloped (MMBbls)	–	–	–	–	**–**
	–	10.2	–	0.3	**10.5**
Natural Gas Liquids (MMBbls):					
Developed (MMBbls)	–	53.8	–	0.1	**53.9**
Undeveloped (MMBbls)	–	–	–	–	**–**
	–	53.8	–	0.1	**53.9**
Total Proved Reserves (Bcfe): [2]					
Developed (Bcfe)	1,540	677	2,954	5	**5,176**
Undeveloped (Bcfe)	34	–	43	–	**77**
	1,574	677	2,997	5	**5,253**
Percent of Total	30%	13%	57%	0%	**100%**
Percent Proved Developed	98%	100%	99%	100%	**99%**
Percent Proved Undeveloped	2%	0%	1%	0%	**1%**
Production (Bcfe)	350	148	375	2	**875**
Capital Investments (in millions) [3]	$ 204	$ 288	$ 86	$ 19	**$ 597**
Total Gross Producing Wells [4]	820	306	4,217	16	**5,359**
Total Net Producing Wells [4]	439	216	2,932	13	**3,600**
Total Net Acreage	245,805 [5]	321,563 [6]	918,535 [7]	3,023,386 [8]	**4,509,289**
Net Undeveloped Acreage	146,096 [5]	161,607 [6]	285,692 [7]	3,010,908 [8]	**3,604,303**
PV-10:					
Pre-Tax (in millions) [9]	$ 183	$ 163	$ 1,325	$ (6)	**$ 1,665**
PV of Taxes (in millions) [9]	–	–	–	–	**–**
After-Tax (in millions) [9]	$ 183	$ 163	$ 1,325	$ (6)	**$ 1,665**
Percent of Total	11%	10%	79%	0%	**100%**
Percent Operated [10]	95%	100%	99%	100%	**98%**

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

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

(3) Total and Other capital investments excludes $26 million related to our E&P service companies.

(4) Represents all producing wells, including wells in which we only have an overriding royalty interest, as of December 31, 2016.

(5) Assuming successful wells are not drilled to develop the acreage and leases are not extended in Northeast Appalachia, leasehold expiring over the next three years will be 63,900 net acres in 2017, 16,066 net acres in 2018 and 11,413 net acres in 2019.

(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended in Southwest Appalachia, leasehold expiring over the next three years will be 39,429 net acres in 2017, 12,267 net acres in 2018 and 10,824 net acres in 2019. Of this acreage, 21,760 net acres in 2017, 3,767 net acres in 2018 and 8,150 net acres in 2019 can be extended for an average of 4.8 years.

(7) Assuming successful wells are not drilled to develop the acreage and leases are not extended in the Fayetteville Shale, leasehold expiring over the next three years will be 453 net acres in 2017, 60 net acres in 2018 and 432 net acres in 2019 (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 the Lower Smackover Brown Dense area, the Sand Wash Basin and New Brunswick, Canada, will be 68,556 net acres in 2017, 21,982 net acres in

2018 and 103,172 net acres in 2019. 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 50,778 net acres in 2017, 83,021 net acres in 2018 and 5,793 net acres in 2019. 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 36,527 net acres in 2017, 51,260 net acres in 2018, and 12,810 net acres in 2019. With regard to our acreage in New Brunswick, Canada, exploration licenses for 2,518,519 net acres were extended through 2021.

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

Proved Undeveloped Reserves

Presented below is a summary of changes in our proved undeveloped reserves for 2014, 2015 and 2016:

CHANGES IN PROVED UNDEVELOPED RESERVES (BCFE)

	Appalachia				
	Northeast	Southwest	Fayetteville Shale	Other [1]	**Total**
December 31, 2013	1,075	–	1,655	7	**2,737**
Extensions, discoveries and other additions [2]	589	–	573	–	**1,162**
Total revision attributable to performance and production [3]	307	–	(130)	(6)	**171**
Price revisions	11	–	24	–	**35**
Developed	(384)	–	(406)	–	**(790)**
Disposition of reserves in place	–	–	–	–	**–**
Acquisition of reserves in place [4]	–	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 [3]	513	158	62	–	**733**
Price revisions	(1,447)	(1,413)	(1,357)	–	**(4,217)**
Developed	(488)	(226)	(330)	–	**(1,044)**
Disposition of reserves in place	–	–	–	(1)	**(1)**
Acquisition of reserves in place	–	–	–	–	**–**
December 31, 2015	**314**	**4**	**125**	**–**	**443**
Extensions, discoveries and other additions	**–**	**–**	**25**	**–**	**25**
Total revision attributable to performance and production [3]	**204**	**–**	**(1)**	**–**	**203**
Price revisions	**(303)**	**(4)**	**(67)**	**–**	**(374)**
Developed	**(181)**	**–**	**(39)**	**–**	**(220)**
Disposition of reserves in place	**–**	**–**	**–**	**–**	**–**
Acquisition of reserves in place	**–**	**–**	**–**	**–**	**–**
December 31, 2016	**34**	**–**	**43**	**–**	**77**

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

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

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

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

As of December 31, 2016, we had 77 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 2016, we invested $103 million in connection with converting 220 Bcfe, or 50%, of our proved undeveloped reserves as of December 31, 2015 into proved developed reserves and added 25 Bcfe of proved undeveloped reserve additions in the Fayetteville Shale. As a result of the commodity price environment in 2016, we had downward price revisions of 374 Bcfe which were slightly offset by a 203 Bcfe increase due to performance revisions. As of December 31, 2015, we had 443 Bcfe of proved undeveloped reserves. During 2015, we invested $869 million in connection with converting 1,044 Bcfe, or 22%, of our proved undeveloped reserves as of December 31, 2014 into proved developed reserves and added 176 Bcfe of proved undeveloped reserve additions in the Appalachian Basin and the Fayetteville Shale. As a result of the depressed commodity price environment in 2015, we had downward price revisions of 4,217 Bcfe which were slightly offset by a 733 Bcfe increase due to performance revisions. 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, 2016 proved reserves include 77 Bcfe of proved undeveloped reserves from 15 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 $11 million when discounted at 10%. We have made a final investment decision and are committed to developing these reserves within five years from the date of initial booking.

We expect that the development costs for our proved undeveloped reserves of 77 Bcfe as of December 31, 2016 will require us to invest an additional $42 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 business, including our revenues, profits, liquidity, growth, ability to repay our debt and the value of our assets" and "Significant capital expenditures are required to replace our reserves and conduct our business" in Item 1A of Part I of this Annual Report and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Reserve Replacement

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 81 Bcf, 420 Bcf and 835 Bcf in 2016, 2015 and 2014, respectively. Additionally, we added 157 Bcfe and 123 Bcfe of reserves in 2016 and 2015, respectively, 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, 2016, we had approximately 245,805 net acres in Northeast Appalachia and had spud or acquired 568 operated wells, 447 of which were on production and 536 of which are horizontal wells. Northeast Appalachia represents 40% of our total net production and 30% of our total reserves as of December 31, 2016. Below is a summary of Northeast Appalachia's operating results for the last three years:

	For the years ended December 31,		
	2016	2015	2014
Acreage			
Net undeveloped acres	**146,096** (1)	174,826	205,491
Net developed acres	**99,709**	95,509	60,582
Total net acres	**245,805**	270,335	266,073
Net Production (Bcf)	**350**	360	254
Reserves			
Reserves (Bcf)	**1,574**	2,319	3,192
Locations:			
Proved developed	**820**	767	524
Proved developed non-producing	**39**	23	13
Proved undeveloped	**2**	36	200
Total locations	**861**	826	737
Gross Operated Well Count Summary			
Spud or acquired	**32**	177 (2)	106 (3)
Completed	**33**	92	104
Wells to sales	**24**	100	88
Capital Investments (in millions)			
Exploratory and development drilling, including workovers	$ **160**	$ 472	$ 571
Acquisition and leasehold	**3**	172	28
Seismic and other	**2**	8	30
Capitalized interest and expense	**39**	58	66
Total capital investments	$ **204**	$ 710	$ 695
Average completed well cost (in millions)	$ **5.3**	$ 5.4	$ 6.1
Average lateral length (feet)	**6,142**	5,403	4,752

(1) Our undeveloped acreage position as of December 31, 2016 had an average royalty interest of 14% and was obtained at an average cost of approximately $1,127 per acre.

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

(3) Includes 5 horizontal and 2 vertical acquired wells.

In 2016, our reserves in Northeast Appalachia decreased by 745 Bcf, which included net downward price revisions of 794 Bcf and production of 350 Bcf, partially offset by net upward performance revisions of 318 Bcf and additions of 81 Bcf.

Our ability to bring our Northeast Appalachia production to market depends on a number of factors including the construction of and/or the availability of capacity on gathering systems and pipelines that we do not own. We refer you to "Midstream 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. In 2016 we disposed of a portion of this acreage that we did not expect to drill for several years. As of December 31, 2016, we had approximately 321,563 net acres in Southwest Appalachia and had a total of 299 horizontal and 4 vertical wells that we operated and that were on production. Southwest Appalachia represents 17% of our total net production and 13% of our total reserves as of December 31, 2016. Below is a summary of Southwest Appalachia's operating results for the last three years:

	For the years ended December 31,		
	2016	2015	2014
Acreage			
Net undeveloped acres	**161,607** (1)	193,582	188,244
Net developed acres	**159,956**	231,516	225,132
Total net acres	**321,563**	425,098	413,376
Net Production (Bcfe)	**148**	143	3
Reserves			
Reserves (Bcfe)	**677**	611	2,297
Locations:			
Proved developed	**306** (2)	1,028	1,034
Proved developed non-producing	**44** (2)	400	124
Proved undeveloped	**–**	1	344
Total locations	**350** (2)	1,429	1,502
Gross Operated Well Count Summary			
Spud or acquired	**17**	48	1,334 (3)
Completed	**17**	38	–
Wells to sales	**18**	47	–
Capital Investments (in millions)			
Exploratory and development drilling, including workovers	$ **111**	$ 248	$ 3
Acquisition and leasehold	**18**	409	5,007
Seismic and other	**1**	2	–
Capitalized interest and expense	**158**	198	2
Total capital investments	$ **288**	$ 857	$ 5,012
Average completed well cost (in millions) (4)	$ **6.5**	$ 6.9	$ –
Average lateral length (feet) (4)	**5,499**	6,985	–

(1) Our undeveloped acreage position as of December 31, 2016 had an average royalty interest of 14%.

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

(3) Includes 323 horizontal and 1,011 vertical wells acquired in CHK and STO acquisitions.

(4) Includes wells only drilled by SWN.

In 2016, our reserves in Southwest Appalachia increased by 66 Bcfe, which included 199 Bcfe of net upward performance revisions and additions of 157 Bcfe, partially offset by production of 148 Bcfe, net downward price revisions of 127 Bcfe and dispositions of 15 Bcfe.

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

As of December 31, 2016, we held leases for approximately 918,535 net acres in the Fayetteville Shale, an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, and had spud a total of 4,741 wells in the play since our commencement of activities there in 2004, of which 4,161 were operated by us and 580 were outside-operated wells. At year-end 2016, 4,037 wells operated by the Company had been drilled and completed overall, including 3,946 horizontal wells. The Fayetteville Shale represents 43% of our total net production and 57% of our total reserves as of December 31, 2016. Below is a summary of the Fayetteville Shale's operating results for the last three years:

	For the years ended December 31,		
	2016	2015	2014
Acreage			
Net undeveloped acres [2]	**285,692** [1]	288,569	267,888
Net developed acres [3]	**632,843**	669,072	620,273
Total net acres	**918,535**	957,641	888,161
Net Production (Bcf)	**375**	465	494
Reserves			
Reserves (Bcf)	**2,997**	3,281	5,069
Locations:			
Proved developed	**4,217**	4,268	4,045
Proved developed non-producing	**311**	231	187
Proved undeveloped	**13**	61	1,213
Total locations	**4,541**	4,560	5,445
Gross Operated Well Count Summary			
Spud or acquired	**4**	155	465
Completed	**34**	262	458
Wells to sales	**43**	260	455
Capital Investments (in millions)			
Exploratory and development drilling, including workovers	$ **63**	$ 484	$ 838
Acquisition and leasehold	**2**	4	7
Seismic and other	**–**	8	4
Capitalized interest and expense	**21**	69	95
Total capital investments	$ **86**	$ 565	$ 944
Average completed well cost (in millions)	$ **3.2**	$ 2.8	$ 2.6
Average lateral length (feet)	**5,717**	5,729	5,440

(1) Our undeveloped acreage position as of December 31, 2016 had an average royalty interest of 13% and was obtained at an average cost of approximately $335 per acre.

(2) Includes 86,631, 31,413 and 432 net undeveloped acres in the Arkoma Basin that have been previously reported as a component of our conventional Arkoma acreage as of December 31, 2016, 2015 and 2014, respectively. We sold our conventional Arkoma properties in 2015 but retained the acreage located within the Fayetteville Shale area.

(3) Includes 141,025, 170,743 and 123,442 net developed acres in the Arkoma Basin that have been previously reported as a component of our conventional Arkoma acreage as of December 31, 2016, 2015 and 2014, respectively. We sold our conventional Arkoma properties in 2015 but retained the acreage located within the Fayetteville Shale area.

In 2016, our reserves in the Fayetteville Shale decreased by 284 Bcf, which included production of 375 Bcf and net downward price revisions of 116 Bcf, partially offset by 163 Bcf of net upward revisions due to well performance and reserve additions of 44 Bcf.

Of the acreage we hold in the Fayetteville Shale, the Ozark Highlands Unit accounts for 158,231 acres and lies entirely within the Ozark National Forest. Following the commencement of two court actions, 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. 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. At year-end 2016, after excluding our acreage in the conventional Arkoma Basin and the federal acreage we hold in the Ozark Highlands Unit, approximately 87% of our 532,648 total net leasehold acres remaining in the Fayetteville Shale was held by production. For more information about our acreage and well count, we refer you to "Properties" in Item 2 of Part I of this Annual Report. We 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.

Other

As of December 31, 2016, we held 3,010,908 net undeveloped acres for the potential development of new resources, of which 2,518,519 net acres were located in New Brunswick, Canada. This compares to 3,661,375 net undeveloped acres held at year-end 2015 and 4,170,687 net undeveloped acres held at year-end 2014.

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

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 6,500 to 12,500 feet. Our leases currently have an approximate 83% average net revenue interest. As of December 31, 2016, we held approximately 127,943 net acres in the area.

Lower Smackover Brown Dense. In July 2011, we announced that we would begin testing a new unconventional liquids rich play targeting the Lower Smackover Brown Dense formation, an unconventional reservoir that ranges in vertical depths from 8,500 to 11,400 feet and appears to be laterally extensive over a large area ranging in thickness from 450 to 700 feet. As of December 31, 2016, we held approximately 146,677 net acres in the area, obtained at an average cost of $466 per acre. Our leases currently have an approximate 80% average net revenue interest. As of December 31, 2016, we had drilled 14 operated wells in the area, 6 of which were currently producing.

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

Acquisitions and Divestitures

In September 2016, the Company sold approximately 55,000 net acres in West Virginia for approximately $422 million, subject to customary post-closing adjustments. As of December 2015, these assets included approximately 11 Bcfe of proved reserves.

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.

Capital Investments

During 2016, we invested a total of approximately $623 million in our E&P business, including $239 million in capital interest and expenses. In 2016, we spudded 53 wells, completed 84 wells, placed 85 wells to sales and had 135 wells in progress at year-end. Of the 135 wells in progress at year-end, 73, 42 and 20 were located in our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale operating areas, respectively, and 35 of these wells are waiting on pipeline or production facilities.

	For the years ended December 31,		
	2016	2015	2014
		(in millions)	
E&P Capital Investments by Type			
Exploratory and development drilling, including workovers	$ **358**	$ 1,226	$ 1,514
Acquisition and leasehold	**23**	607	5,328
Seismic expenditures	**1**	6	56
Drilling rigs, sand facility and other	**2**	40	116
Capitalized interest and other expenses	**239**	379	240
Total E&P capital investments	$ **623**	$ 2,258	$ 7,254
E&P Capital Investments by Area			
Northeast Appalachia	$ **165**	$ 652	$ 629
Southwest Appalachia	**130**	659	5,010
Fayetteville Shale	**65**	496	849
Other	**24**	72	526
Capitalized interest and other expenses	**239**	379	240
Total E&P capital investments	$ **623**	$ 2,258	$ 7,254

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 2017.

Sales, Delivery Commitments and Customers

Sales. Our daily natural gas equivalent production averaged 2,391 MMcfe in 2016, compared to 2,675 MMcfe in 2015 and 2,105 MMcfe in 2014. Total natural gas equivalent production was 875 Bcfe in 2016, down from 976 Bcfe in 2015 and up from 768 Bcfe in 2014. Our natural gas production was 788 Bcf in 2016, compared to 899 Bcf in 2015 and 766 Bcf in 2014. The decrease in production in 2016 resulted primarily from normal declines in production from existing wells that were not fully offset by production from new wells, given our reduced drilling activities. In particular, we experienced a 90 Bcf decrease in net production from our Fayetteville Shale properties, a 10 Bcf decrease in net production from our Northeast Appalachia properties and a 6 Bcfe decrease in other properties, which was partially offset by a 5 Bcfe increase in net production from our Southwest Appalachia properties. 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. We produced 2,192 MBbls of oil in 2016, compared to 2,265 MBbls of oil in 2015 and 235 MBbls of oil in 2014. Our oil production has increased from 2014 levels primarily due to the acquisition of natural gas and oil properties in Southwest Appalachia in December 2014. In 2016, we produced 12,372 MBbls of NGLs, compared to 10,702 MBbls and 231 MBbls of NGLs in 2015 and 2014, respectively, primarily due to the December 2014 acquisition of natural gas and oil properties in Southwest Appalachia.

Sales of natural gas, oil and NGL production are conducted under contracts that reflect current prices and are subject to seasonal price swings. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand for our production. We regularly enter into various derivative and other financial arrangements with respect to a portion of our projected 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, 2016, we had New York Mercantile Exchange, or NYMEX, commodity price derivatives in place on 560 Bcf, 240 Bcf and 62 Bcf of our targeted 2017, 2018 and 2019 natural gas production, respectively. We also had commodity derivatives in places on 365 MBbls of our targeted ethane production for 2017 through 2018. As of February 21, 2017, we had NYMEX commodity price derivatives in place on 515 Bcf, 272 Bcf and 80 Bcf of our targeted 2017, 2018 and 2019 natural gas production, respectively. We intend to financially protect pricing on a large portion of expected future production volumes designed to assure certain desired levels of cash flow. We refer you to Item 7A of Part II of this Annual Report, “Quantitative and Qualitative Disclosures about Market Risks,” for further information regarding our derivatives and risk management as of December 31, 2016.

Including the effect of settled derivatives, we realized an average price of $1.64 per Mcf for our natural gas production in 2016, compared to $2.37 per Mcf in 2015 and $3.72 per Mcf in 2014. Our derivative activities increased our average realized natural gas sales price by $0.05 per Mcf in 2016, compared to an increase of $0.46 per Mcf in 2015 and a decrease of $0.02 per Mcf in 2014. Our average oil price realized was $31.20 per barrel in 2016, compared to $33.25 per barrel in 2015 and $79.91 per barrel in 2014. Our average realized NGL price was $7.46 per barrel in 2016, compared to $6.80 per barrel in 2015 and $15.72 per barrel in 2014. We did not use derivatives to financially protect our 2016, 2015 or 2014 oil and NGL production.

During 2016, the average price we received for our natural gas production, excluding the impact of derivatives, was approximately $0.87 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, 2016, we have partially mitigated the volatility of basis differentials by protecting basis on approximately 277 Bcf and 78 Bcf of our expected 2017 and 2018 natural gas production, respectively, through physical sales arrangements and financial derivatives at a basis differential to NYMEX natural gas prices of approximately ($0.50) per Mcf and ($0.34) per Mcf for 2017 and 2018, respectively. We refer you to Note 4 to our consolidated financial statements for additional discussion about our derivatives and risk management activities.

Delivery Commitments. As of December 31, 2016, we had natural gas delivery commitments of 394 Bcf in 2017 and 126 Bcf in 2018 under existing agreements. These amounts are well below our expected 2017 natural gas production from our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale divisions and expected 2018 production from our available reserves, which are not subject to any priorities or curtailments that may affect quantities delivered to our customers or any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond our control that may affect our ability to meet our contractual obligations other than those discussed in Item 1A “Risk Factors” of Part I of this Annual Report. We expect to be able to fulfill all of our short-term and long-term contractual obligations to provide natural gas from our own production of available reserves; however, if we are unable to do so, we may have to purchase natural gas at market to fulfill our obligations.

Customers. Our customers include major energy companies, utilities and industrial purchasers of natural gas. During the years ended December 31, 2016, 2015 and 2014, 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, its gathering and transportation (whether we are shipping or operate the transmission facilities) and the securing of labor and equipment required to conduct our operations. Our competitors include major oil and natural gas companies, other independent oil and natural gas companies, individual producers and operators and developers of gathering and transportation systems. Many of these competitors have financial and other resources that substantially exceed those available to us. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. We also face competition in accessing pipeline and other services to transport our product to market, particularly in the northeastern United States, where potential production levels exceed currently available capacity.

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

Regulation

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

Currently in the United States, the price at which natural gas 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.

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

Midstream Services

Our Midstream Services segment complements our E&P initiatives and, in some areas, competes 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 since the sale of our gathering assets in northeast Pennsylvania and Texas in 2015.

Our operating income from this segment was $209 million on revenues of $2.6 billion in 2016, compared to $583 million on revenues of $3.1 billion in 2015 and $361 million on revenues of $4.4 billion in 2014. Operating income in 2015 includes a $277 million net gain related to the sale of our northeast Pennsylvania and East Texas gathering assets. Excluding the gain on sales, operating income decreased $97 million in 2016 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 in 2015. Revenues decreased in 2016 primarily due to a decrease in the price received for volumes marketed, a decrease in volumes marketed and a decrease in volumes gathered. Excluding the gains on sales, 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 in 2015. Revenues decreased in 2015 from 2014 levels primarily due to the prices received for volumes marketed. Cash flow from operations generated by our Midstream Services segment was $222 million in 2016, compared to $540 million in 2015 and $172 million in 2014. The decrease in 2016 was primarily due to decreased revenues, partially offset by a decrease in operating costs and expenses. During the years ended December 31, 2016, 2015 and 2014, 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 $21 million related to our gathering activities in 2016 and had gathering revenues of $378 million, compared to $58 million invested and revenues of $491 million in 2015 and $144 million invested and revenues of $562 million in 2014. During 2015, we divested our gathering assets in northeast Pennsylvania and East Texas. The divested gathering assets accounted for $21 million and $67 million of our gathering revenues for the years ended December 31, 2015 and 2014, respectively.

In 2016, we gathered approximately 600 Bcf of natural gas in the Fayetteville Shale area, including 42 Bcf of natural gas from third-party operated wells. 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. In 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. At the end of 2016, we had approximately 2,045 miles of pipe from the individual wellheads to the transmission lines and compression equipment representing in aggregate approximately 477,095 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 primarily involving the marketing of our own natural gas production and that of royalty owners in our wells. Additionally, we manage portfolio and basis risk, acquire transportation rights on third-party pipelines and in limited circumstances, purchase third-party natural gas to fulfill commitments specific to a geographic location. During 2016, we marketed 1,062 Bcfe, compared to 1,127 Bcfe in 2015 and 904 Bcf in 2014. Of the total gas volumes marketed, production from our affiliated E&P operations accounted for 93% in 2016, compared to 97% in 2015 and 2014. Our Midstream Services segment also marketed approximately 65% of our combined oil and NGL production for the year ended December 31, 2016, compared to 60% in 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 by mid-2018.

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 2018 as a result of a longer than expected regulatory and permitting process.

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.

Southwest Appalachia

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, which was later reduced to 76,900 Mcf per day as a result of the sale of a portion of our West Virginia assets. 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 mid to late 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, 2016, we had 475,000 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.

Fayetteville Shale

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, with initial terms ending in 2019 and 2020, respectively.

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 premium Gulf Coast and southeastern United States markets. These interconnecting pipelines include Natural Gas Pipeline, Mississippi River Transmission, 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, 2016, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $8.4 billion, $3.4 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. We also have guarantee obligations of up to $862 million of that amount.

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

Competition

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

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

Environmental Regulation

General. Our operations are subject to environmental regulation in the jurisdictions in which we operate. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements to drill or operate wells and also regulate the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the prevention and cleanup of pollutants and other matters. We maintain insurance 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 2016 oil accounted for 2% of our total production, compared to less than 1% of our total production for 2015 and 2014, although we expect this percentage to increase as we continue to develop our Southwest Appalachia assets.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration for and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed on them may be subject to CERCLA, the Clean Water Act, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

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

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

Hydraulic Fracturing. We utilize hydraulic fracturing in drilling wells as a means of maximizing their productivity. It is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas, and associated liquids from dense and deep rock formations. 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 May 2016, the EPA finalized additional regulations to control methane and volatile organic compound emissions from certain oil and gas equipment and operations. The EPA also recently finalized pretreatment standards that would prohibit the indirect discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned treatment works. Based on our current operations and practices, management believes, such newly promulgated rules will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management's view may change in the future.

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

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 it is satisfied with a list of conditions. In May 2016, the provincial government announced that the moratorium would continue in effect indefinitely. Unless and until the moratorium is lifted, we will not be able to continue our activities on our assets in New Brunswick.

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

In addition, concerns have been raised about the potential for 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, subject to regulatory restrictions relating to seismicity. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others.

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

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

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

Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions. The agreement entered into effect in November 2016 after more than 70 nations, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. 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, 2016, we had 1,469 total employees. None of our employees were covered by a collective bargaining agreement at year-end 2016. We believe that our relationships with our employees are good.

Executive Officers of the Registrant

Name	Age [1]	Officer Position
William J. Way	57	President and Chief Executive Officer
Mark K. Boling	59	Executive Vice President and President V+ Development Solutions
R. Craig Owen	47	Senior Vice President and Chief Financial Officer
Jennifer N. McCauley	53	Senior Vice President – Administration
John C. Ale	62	Senior Vice President, General Counsel and Secretary
John E. Bergeron, Jr.	59	Senior Vice President – E&P Operations
Paul W. Geiger III	45	Senior Vice President – Corporate Development
Randy L. Curry	59	Senior Vice President – Midstream
James W. Vick	55	Senior Vice President – Business Information Systems
C. Greg Stoute	55	Vice President – Health, Safety, Environmental and Regulatory

(1) As of February 21, 2017

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. 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.

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

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

Mr. Bergeron was appointed Senior Vice President – E&P in April 2016. From April 2014 to March 2016, he served as Senior Vice President, Northeast Appalachia Division. Since joining the Company in 2007, he served as Senior Vice President, Fayetteville Shale Division; Vice President and General Manager, Fayetteville Shale Division; Vice President, Economic Planning and Acquisitions; and as Vice President, Fayetteville Shale Planning and Technology.

Mr. Geiger was appointed Senior Vice President – Corporate Development in April 2016. Prior to that, he served as Senior Vice President of the West Virginia division in 2015 and of the Fayetteville Shale division since joining the Company in April 2014. Prior to joining Southwestern Energy Company, Mr. Geiger served as Senior Vice President of Operations at Quantum Resources Management and QR Energy since October 2012.

Mr. Curry as appointed Senior Vice President – Midstream in 2014. Beginning in January 2003, he served as President of Chevron Natural Gas. Prior to that, Mr. Curry held various management positions with Chevron's Global Gas and Midstream organizations.

Mr. Vick was appointed Senior Vice President – Business Information Services in November 2011. Prior to that he was a Principal with Deloitte Consulting's Information Management practice.

Mr. Stoute was appointed Vice President of Health, Safety, Environmental and Regulatory in January 2016. Since joining the Company in 2005 as a senior staff reservoir engineer, he has worked in various leadership positions within SWN and was most recently General Manager for the New Ventures team.

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 23, 2017, 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.

GLOSSARY OF CERTAIN INDUSTRY TERMS

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

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

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

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

"Bcf" One billion cubic feet of natural gas.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"MBbls" One thousand barrels of oil or other liquid hydrocarbons.

"Mcf" One thousand cubic feet of natural gas.

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

"MMBbls" One million barrels of oil or other liquid hydrocarbons.

"MMBtu" One million British thermal units (Btus).

"MMcf" One million cubic feet of natural gas.

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

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

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

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

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

"NGL" Natural gas liquids.

"NYMEX" The New York Mercantile Exchange.

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

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

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

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

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

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

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

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

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

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

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

"Proved 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.

"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."

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

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

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

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

ITEM 1A. RISK FACTORS

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

Natural gas, oil and natural gas liquids prices greatly affect our business, including our revenues, profits, liquidity, growth, ability to repay our debt and the value of our assets.

Our revenues, profitability, liquidity, growth, ability to repay our debt and the value of our assets greatly depend on prices for natural gas, oil and 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 2016 and 2015, our production was approximately 90% and 92% natural gas, respectively, and during this period spot prices ranged from a low of $1.49 per Mcf in March 2016 to a high of $3.80 per Mcf in December 2016.

In our exploration and production business, lower natural gas, oil and NGL prices directly reduce our revenues and thus our operating income and cash flow. Lower prices also reduce the projected profitability of further drilling and therefore are likely to reduce our drilling activity, which in turn means we will have fewer wells on production in the future. Lower prices also reduce the value of our assets, both by a direct reduction in what the production would be worth and by making some properties uneconomic, resulting in impairments to the recorded value of our reserves and non-cash charges to earnings. For example, in 2016, we reported non-cash impairment charges on our natural gas and oil properties totaling $2,321 million, primarily resulting from decreases in trailing 12-month average first-day-of-the-month natural gas prices throughout 2016, as compared to 2015, and the impairment of certain undeveloped leasehold interests. Further impairments in subsequent periods could occur if the trailing 12-month commodity prices continue to fall as compared to the average used in prior periods.

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

As of December 31, 2016, we had $4.7 billion of debt outstanding, consisting principally of $3.2 billion in senior notes maturing in various increments from 2017 to 2025 and $1.5 billion in term loans due in 2020. At current commodity price levels, our net cash flow from operations is substantially higher than our interest obligations under this debt, but significant drops in realized prices could affect our ability to pay our current obligations or refinance our debt as it becomes due.

Moreover, general industry conditions may make it difficult or costly to refinance increments of this debt as it matures. While our indentures do not contain significant covenants restricting our operations and other activities, our 2016 credit agreement contains financial covenants with which we must comply. We refer you to the risk factor "Our current and future levels of indebtedness may adversely affect our results and limit our growth." Our inability to pay our current obligations or refinance our debt as it becomes due could have a material and adverse effect on our company. The drop in prices in the past three years has reduced our revenues, profits and cash flow, caused us to record significant asset impairments and led us to reduce both our level of capital investing and our workforce, which has caused us to incur significant expenses relating to employee terminations. Further price decreases could have similar consequences. Similarly, a rise in prices to levels experienced into the middle of 2014 could significantly increase our revenues, profits and cash flow, which could be used to expand capital investments.

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

Our activities require substantial capital investment. We intend to fund our capital investing through net cash flows from operations, plus the uninvested amount of the proceeds from our July 2016 equity offering and West Virginia acreage sale earmarked for capital investment (approximately $200 million remaining as of December 31, 2016). 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 investing, we could experience a further reduction in drilling new wells and acquiring new acreage, a loss of properties and a decline in our cash flow from operations and natural gas, oil and natural gas liquids production and reserves.

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 exploration, development or acquisition activities, our proved reserves and production will decline over time. Recovery of such reserves will require significant capital investment and successful drilling operations. Thus, our future natural gas, oil and NGL 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 impact our ability to access debt markets in the future, affect the market value of our senior notes and increase our corporate borrowing costs. Such ratings are limited in scope, and do not address all material risks relating to us, but rather reflect only the view of each rating agency at the time the rating is issued of the likelihood we will be able to repay our debt. An explanation of the significance of each rating may be obtained from the applicable rating agency. As of February 21, 2017, we were rated Ba3 by Moody's, BB- by Standard and Poor's and BB by Fitch Investor Services. There can be no assurance that such credit ratings will remain in effect for any given period of time or that such ratings will not be lowered, suspended or withdrawn entirely by the rating agencies, if, in each rating agency's judgment, circumstances so warrant.

Actual downgrades in our credit ratings may also impact our liquidity. Many of our existing commercial contracts contain, and future commercial contracts may contain, provisions permitting the counterparty to require increased security upon the occurrence of a downgrade in our credit rating. Providing additional security, such as posting letters of credit, could reduce our available cash or our liquidity under our revolving credit facility for other purposes. We had $174 million of letters of credit outstanding at December 31, 2016. The amount of additional security would depend on the severity of the downgrade from the credit rating agencies, and a downgrade could result in a decrease in our liquidity.

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

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

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

Leases on approximately 159,176 net acres of our Fayetteville Shale acreage (including 158,231 net acres held on federal lands that are currently suspended by the Bureau of Land Management) will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. Approximately 91,379 and 62,520 net acres of our Northeast Appalachia and Southwest Appalachia acreage, respectively, will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. Our ability to drill wells depends on a number of factors, including certain factors that are beyond our control, such as the ability to obtain permits on a timely basis or to compel landowners or lease holders on adjacent properties to cooperate. Further, we may not have sufficient capital to drill all the wells necessary to hold the acreage without increasing our debt levels, or given price projections at the time, drilling may not be estimated to achieve a PVI of at least 1.3. To the extent we do not drill the wells, our rights to acreage can be lost.

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

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

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

For our non-operated properties, we 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 pipelines;
- disruption or failure of information technology systems and network infrastructure due to various causes, including unauthorized access or attack; and
- leaks of natural gas or ethane as a result of the malfunction of equipment or facilities.

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

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

At December 31, 2016, we had long-term indebtedness of $4.6 billion, including borrowings of $327 million and $1.2 billion under our term loan credit agreements. 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 certain debt;
- making certain investments;

- creating liens on our assets; and
- selling assets.

Under the 2013 revolving credit 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 post-retirement liabilities. Therefore, under the 2013 revolving credit facility, our adjusted capital structure as of December 31, 2016 was 34% debt and 66% equity. Under our 2016 credit agreement, we must maintain certain covenants, including, among others, the following financial covenants:

- Minimum liquidity of $300 million, subject to increase up to $500 million upon certain conditions;
- Minimum interest coverage ratio of no less than (i) with respect to any fiscal quarter ended on or before December 31, 2016, 0.75x, (ii) with respect to any fiscal quarter ending on or after March 31, 2017 and on or before December 31, 2017, 1.00x, (iii) with respect to any fiscal quarter ending on or after March 31, 2018 and on or before December 31, 2018, 1.25x and (iv) with respect to any fiscal quarter ending on or after March 31, 2019, 1.50x, commencing with the fiscal quarter ending June 30, 2016; and
- With respect to the secured term loan, a minimum collateral coverage ratio of no less than 1.50x of the secured term loan. Currently this collateral consists of most of our interest in E&P properties in the Fayetteville Shale area, the equity in our subsidiaries and cash and marketable securities.

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 investing and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital investing, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- detracting from our ability to successfully withstand a downturn in our business or the economy generally.

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

If we fail to comply with the covenants and other restrictions, it could lead to an event of default and the acceleration of our obligations under the notes or our other financing agreements, and in the case of the lease agreements for drilling rigs, 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 low of $1.71 in February 2016 and a high of $3.23 in December 2016 based on the settlement price of the monthly contract at expiration. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure that we will be able to generate sufficient cash flow to pay the interest on our debt, to meet our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations. The terms of our financing agreements may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure that any such proposed offering, refinancing or sale of assets can be successfully completed or, if completed, that the terms will be favorable to us.

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

Through December 31, 2016, we had invested approximately $1.3 billion in our gas gathering system built for the Fayetteville Shale. We may make further substantial investments in the expansion of this system. Our ability to recover the costs of these investments depends on production from the Fayetteville Shale, and reduced production volumes, whether due to lower drilling activity due to lower prices or failure to produce significant quantities of gas in relevant timeframes, can adversely affect our ability to recover these investments.

We also have entered into gathering agreements in other producing areas and multiple long-term firm transportation agreements relating to natural gas volumes from all our producing areas. As of December 31, 2016, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately $8.4 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.

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

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

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

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, subject to regulatory restrictions relating to seismic.

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, 2016, 43% of our total estimated proved reserves were attributable to properties located in the Appalachian Basin and 57% 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 market natural gas, oil and NGLs, to secure trained personnel and appropriate services, to obtain additional properties and to raise capital.

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

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

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

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

Our natural gas and oil exploration and production operations are subject to complex and stringent federal, state and local laws and regulations, including those governing environmental protection, the occupational health and safety aspects of our operations, the discharge of materials into the environment, and the protection of certain plant and animal species. See “Other — Environmental Regulation” in Item 1 of Part I of this Annual Report for a description of the laws and regulations that affect us. 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 NGLs 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 May 2016, the EPA finalized additional regulations to control methane and volatile organic compound emissions from certain oil and gas equipment and operations.

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

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

In December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions. The agreement entered into force in November 2016 after more than 70 nations, including the United States, ratified or otherwise indicated their intent to be bound by the agreement. 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.

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

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

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

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

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

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

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

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

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

Various factors could materially affect our ability to dispose of assets 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.

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

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

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

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

Certain 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 former President Obama in his fiscal year 2017 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.

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

Deferred tax assets, including net operating loss carryforwards, represent future savings of taxes that would otherwise be paid in cash. At December 31, 2016, the Company had substantial amounts of net operating loss carryforwards for U.S. federal and state income tax purposes. These loss carryforwards will eventually expire if not utilized. In addition, limitations may exist upon use of these carryforwards in the event that a change in control of the Company occurs. A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. At December 31, 2016, the Company recorded a valuation allowance against its entire deferred tax asset, including the portion related to the remaining net operating loss carryforwards. This allowance was recorded primarily as a result of cumulative book losses experienced over the three-year period ending December 31, 2016. If we experience additional book losses, we may be required to increase our valuation allowance against our deferred tax assets.

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

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

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

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

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

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

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

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

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

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

Common stockholders will be diluted if additional shares are issued.

In July 2016, we consummated an underwritten offering of 98.9 million shares of our common stock pursuant to an effective registration statement filed with the Securities and Exchange Commission, with net proceeds of the offering totaling approximately $1,247 million after underwriting discounts and offering expenses. The proceeds from the offering were used to repay $375 million of the $750 million term loan entered into in November 2015 and to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of our outstanding senior notes due in the first quarter of 2018. The remaining net proceeds of the offering have been and will be used for general corporate purposes, including the completion of wells already drilled or the funding of other capital projects.

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. Dividends on our 6.25% Series B Mandatory Preferred Stock are payable quarterly until they convert to common stock in January 2018, which dividends we may pay in cash or shares of our common stock. During 2016, we issued approximately 6.9 million shares of our common stock to satisfy our dividend obligations, and we may continue to issue common stock in satisfaction of our dividend obligation in 2017. 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 2016 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed “2016 Proved Reserves by Category and Summary Operating Data” in “Business – Exploration and Production – Our Proved Reserves” in Item 1 of this Annual Report and incorporated by reference into this Item 2.

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

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

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

Leasehold acreage as of December 31, 2016

	Undeveloped		Developed		**Total**	
	Gross	Net	Gross	Net	**Gross**	**Net**
Appalachia:						
Northeast [1]	152,019	146,096	104,888	99,709	**256,907**	**245,805**
Southwest [2]	362,573	161,607	264,948	159,956	**627,521**	**321,563**
Fayetteville Shale [3]	368,305	285,692	985,459	632,843	**1,353,764**	**918,535**
Other:						
US – Brown Dense [4]	190,638	142,184	4,903	4,493	**195,541**	**146,677**
US – Sand Wash Basin [5]	172,430	119,958	11,181	7,985	**183,611**	**127,943**
US – Other [6]	606,241	230,247	–	–	**606,241**	**230,247**
Canada – New Brunswick [7]	2,518,519	2,518,519	–	–	**2,518,519**	**2,518,519**
	4,370,725	3,604,303	1,371,379	904,986	**5,742,104**	**4,509,289**

(1) Assuming successful wells are not drilled to develop the acreage and leases are not extended in Northeast Appalachia, leasehold expiring over the next three years will be 63,900 net acres in 2017, 16,066 net acres in 2018 and 11,413 net acres in 2019.

(2) Assuming successful wells are not drilled to develop the acreage and leases are not extended in Southwest Appalachia, leasehold expiring over the next three years will be 39,429 net acres in 2017, 12,267 net acres in 2018 and 10,824 net acres in 2019. Of this acreage, 21,760 net acres in 2017, 3,767 net acres in 2018 and 8,150 net acres in 2019 can be extended for an average of 4.8 years.

(3) Assuming successful wells are not drilled to develop the acreage and leases are not extended in the Fayetteville Shale, leasehold expiring over the next three years will be 453 net acres in 2017, 60 net acres in 2018 and 432 net acres in 2019 (excluding 158,231 net acres held on federal lands which are currently suspended by the Bureau of Land Management).

(4) Assuming successful wells are not drilled to develop the acreage and leases are not extended in the Lower Smackover Brown Dense, leasehold expiring over the next three years will be 50,778 net acres in 2017, 83,021 net acres in 2018 and 5,793 net acres in 2019.

(5) Assuming successful wells are not drilled to develop the acreage and leases are not extended in the Sand Wash Basin, leasehold expiring over the next three years will be 36,527 net acres in 2017, 51,260 net acres in 2018 and 12,810 net acres in 2019.

(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 68,556 net acres in 2017, 21,982 net acres in 2018 and 103,172 net acres in 2019.

(7) Assuming successful wells are not drilled to develop the acreage and our exploration license agreements are not extended, the full acreage of 2,518,519 will expire in March 2021.

Producing wells as of December 31, 2016

	Natural Gas		Oil		**Total**		Gross Wells
	Gross	Net	Gross	Net	**Gross**	**Net**	Operated
Appalachia:							
Northeast	506	446	–	–	**506**	**446**	453
Southwest	324	228	–	–	**324**	**228**	303
Fayetteville Shale	4,705	3,242	–	–	**4,705**	**3,242**	4,039
Other	11	8	14	14	**25**	**22**	25
	5,546	3,924	14	14	**5,560**	**3,938**	4,820

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

	Exploratory					
	Productive Wells		Dry Wells		**Total**	
Year	Gross	Net	Gross	Net	**Gross**	**Net**
2016						
Appalachia:						
Northeast	**1.0**	**1.0**	**–**	**–**	**1.0**	**1.0**
Southwest	**–**	**–**	**–**	**–**	**–**	**–**
Fayetteville Shale	**–**	**–**	**–**	**–**	**–**	**–**
Other	**–**	**–**	**–**	**–**	**–**	**–**
Total	**1.0**	**1.0**	**–**	**–**	**1.0**	**1.0**
2015						
Appalachia:						
Northeast	1.0	1.0	–	–	**1.0**	**1.0**
Southwest	–	–	–	–	**–**	**–**
Fayetteville Shale	–	–	–	–	**–**	**–**
Other	2.0	2.0	–	–	**2.0**	**2.0**
Total	3.0	3.0	–	–	**3.0**	**3.0**
2014						
Appalachia:						
Northeast	3.0	2.9	–	–	**3.0**	**2.9**
Southwest	–	–	–	–	**–**	**–**
Fayetteville Shale	–	–	–	–	**–**	**–**
Other	9.0	9.0	–	–	**9.0**	**9.0**
Total	12.0	11.9	–	–	**12.0**	**11.9**

	Development					
	Productive Wells		Dry Wells		**Total**	
Year	Gross	Net	Gross	Net	**Gross**	**Net**
2016						
Appalachia:						
Northeast	**23.0**	**22.9**	**–**	**–**	**23.0**	**22.9**
Southwest	**18.0**	**13.4**	**–**	**–**	**18.0**	**13.4**
Fayetteville Shale	**43.0**	**35.2**	**–**	**–**	**43.0**	**35.2**
Other	**–**	**–**	**–**	**–**	**–**	**–**
Total	**84.0**	**71.5**	**–**	**–**	**84.0**	**71.5**
2015						
Appalachia:						
Northeast	99.0	98.5	–	–	**99.0**	**98.5**
Southwest	63.0	36.6	–	–	**63.0**	**36.6**
Fayetteville Shale	265.0	209.4	–	–	**265.0**	**209.4**
Other	–	–	–	–	**–**	**–**
Total	427.0	344.5	–	–	**427.0**	**344.5**
2014						
Appalachia:						
Northeast	104.0	88.2	–	–	**104.0**	**88.2**
Southwest	–	–	–	–	**–**	**–**
Fayetteville Shale	468.0	377.9	–	–	**468.0**	**377.9**
Other	–	–	–	–	**–**	**–**
Total	572.0	466.1	–	–	**572.0**	**466.1**

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, 2016

	Gross	Net
Drilling:		
Appalachia:		
Northeast	57.0	56.4
Southwest	20.0	14.9
Fayetteville Shale	17.0	16.6
Other	–	–
Total	**94.0**	**87.9**
Completing:		
Appalachia:		
Northeast	16.0	15.9
Southwest	22.0	16.9
Fayetteville Shale	3.0	2.9
Other	–	–
Total	**41.0** [(1)]	**35.7**
Drilling & Completing:		
Appalachia:		
Northeast	73.0	72.3
Southwest	42.0	31.8
Fayetteville Shale	20.0	19.5
Other	–	–
Total	**135.0**	**123.6**

(1) Includes 35 gross 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,		
	2016	2015	2014
Natural Gas			
Production (Bcf):			
Northeast Appalachia	**350**	360	254
Southwest Appalachia	**62**	67	2
Fayetteville Shale	**375**	465	494
Other	**1**	7	16
Total	**788**	899	766
Average realized gas price per Mcf, excluding derivatives:			
Northeast Appalachia	**$ 1.34**	$ 1.62	$ 3.48
Southwest Appalachia	**1.71**	1.92	3.61
Fayetteville Shale	**1.80**	2.12	3.86
Total	**$ 1.59**	$ 1.91	$ 3.74
Average realized gas price per Mcf, including derivatives	**$ 1.64**	$ 2.37	$ 3.72
Oil			
Production (MBbls):			
Southwest Appalachia	**2,041**	2,036	45
Other	**151**	229	190
Total	**2,192**	2,265	235
Average realized oil price per Bbl:			
Southwest Appalachia	**$ 30.59**	$ 31.80	$ 41.28
Other	**39.44**	46.21	89.04
Total	**$ 31.20**	$ 33.25	$ 79.91
NGL			
Production (MBbls):			
Southwest Appalachia	**12,317**	10,640	182
Other	**55**	62	49
Total	**12,372**	10,702	231
Average realized NGL price per Bbl:			
Southwest Appalachia	**$ 7.41**	$ 6.76	$ 10.44
Other	**17.33**	14.51	35.22
Total	**$ 7.46**	$ 6.80	$ 15.72
Total Production (Bcfe)			
Northeast Appalachia	**350**	360	254
Southwest Appalachia	**148**	143	3
Fayetteville Shale	**375**	465	494
Other	**2**	8	17
Total	**875**	976	768
Average Production Cost			
Cost per Mcfe, excluding ad valorem and severance taxes:			
Northeast Appalachia	**$ 0.76**	$ 0.71	$ 0.83
Southwest Appalachia	**1.05**	1.39	1.17
Fayetteville Shale	**0.89**	0.91	0.92
Total	**$ 0.87**	$ 0.92	$ 0.91

During 2016, we were required to file Form 23, “Annual Survey of Domestic Oil and Gas Reserves,” with the U.S. Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in “Supplemental Oil and Gas Disclosures” in Item 8 of Part II of this Annual Report. The primary differences are that Form 23 reports gross reserves, including the royalty owners’ share, and includes reserves for only those properties of which we are the operator.

Miles of Pipe

As of December 31, 2016, our Midstream Services segment had 2,045 miles and 16 miles of pipe in its gathering systems located in Arkansas and Louisiana, respectively.

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and natural gas industry. Our properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which we believe do not materially interfere with the use of or affect the value of such properties. Substantially all our Fayetteville Shale properties are subject to liens securing our 2016 credit facility. 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.

Berry-Helfand (Tovah Energy)

In February 2009, one of our subsidiaries was added as a defendant in a case then styled Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et al., then pending in the 273rd District Court in Shelby County, Texas. The plaintiff alleged that the subsidiary used information provided by the plaintiff under a confidentiality agreement, which she claimed, among other things, breached the agreement and constituted a trade secret. Following a trial in December 2010, the court awarded approximately $11 million in actual damages and approximately $24 million in disgorgement of profits, along with interest and attorneys' fees. Both sides appealed, and in July 2013 the Texas Court of Appeals for the Twelfth District reversed on all claims except misappropriation of trade secrets, reduced the judgment to the actual damages award, along with interest and attorneys' fees, and ordered the case remanded for an award of attorneys' fees to our subsidiary on one of the claims on which judgment was reversed. Both parties petitioned the Supreme Court of Texas for review. In June 2016, the Supreme Court ruled that insufficient evidence supported the damage award and remanded the case for a new trial. The parties subsequently reached a settlement, the amount of which is reflected in our financial statements as of, and for the period ended, December 31, 2016.

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

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

ITEM 4. MINE SAFETY DISCLOSURES

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

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 21, 2017, the closing price of our common stock trading under the symbol "SWN" was $8.59 and we had 3,283 stockholders of record. The following table presents, for each of the periods indicated, the high and low reported sales prices for our common stock trading under the symbol "SWN" as reported on the NYSE:

	Range of Market Prices					
Quarter Ended	2016		2015		2014	
	High	Low	High	Low	High	Low
March 31	**$ 9.90**	**$ 5.30**	$ 28.02	$ 21.46	$ 46.90	$ 37.25
June 30	**$ 15.45**	**$ 7.55**	$ 29.61	$ 22.40	$ 49.16	$ 44.01
September 30	**$ 15.59**	**$ 11.42**	$ 22.84	$ 11.84	$ 45.52	$ 34.82
December 31	**$ 14.40**	**$ 9.14**	$ 13.90	$ 5.00	$ 37.26	$ 26.75

We do not currently pay dividends on our common stock.

Issuer Purchases of Equity Securities

The table below sets forth information with respect to purchases of our common stock made by us or on our behalf during the quarter ended December 31, 2016:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 2016	–	$ –	n/a	n/a
November 2016	–	$ –	n/a	n/a
December 2016	265,058	$ 11.71	n/a	n/a
Total fourth-quarter 2016:	265,058	$ 11.71	n/a	n/a

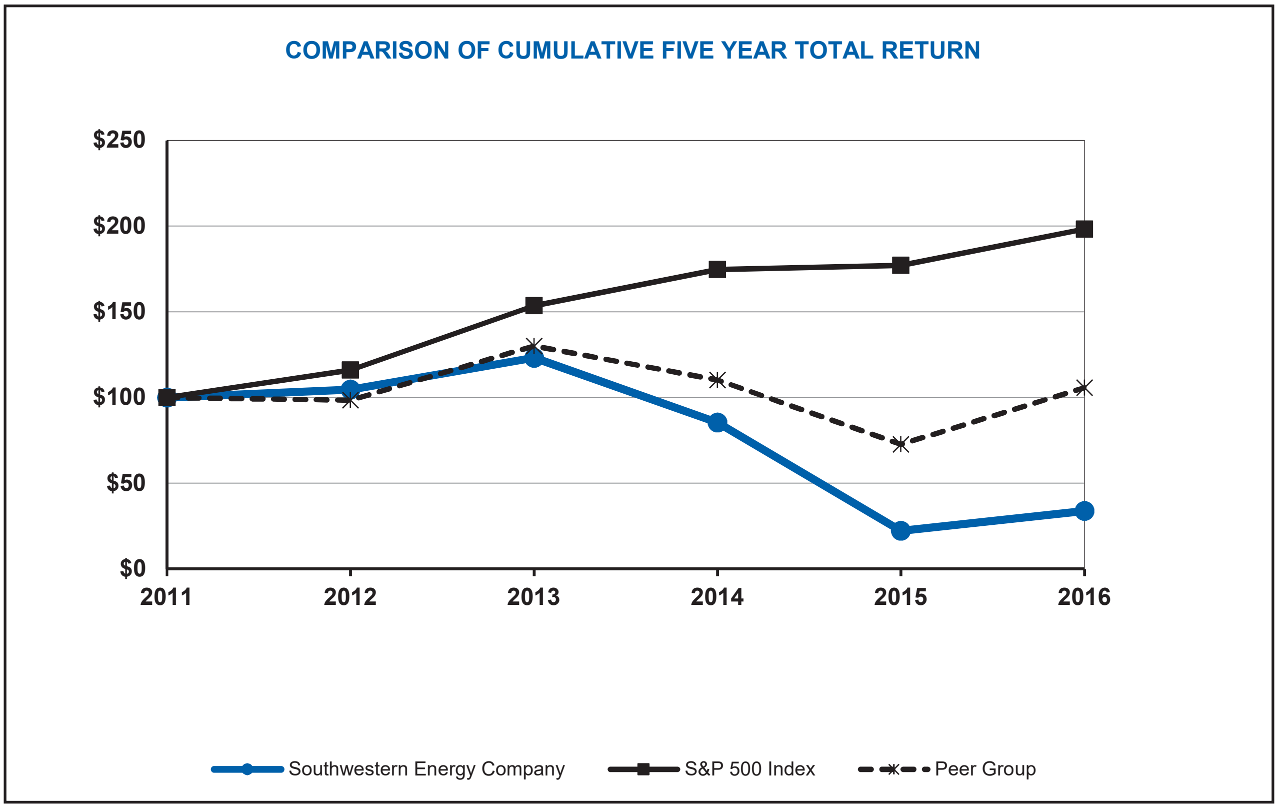
(1) Reflects shares retired by us to satisfy applicable tax withholding obligations due on employee stock plan share issuances. All changes in common stock in treasury in 2016 were due to purchases and sales of shares held on behalf of participants in a non-qualified deferred compensation supplemental retirement savings plan.

Recent Sales of Unregistered Equity Securities

We did not sell any unregistered equity securities during 2016, 2015 or 2014. 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, 2016.

STOCK PERFORMANCE GRAPH

The following graph compares, for the last five years, the performance of our common stock to the S&P 500 Index and our peer group. Our peer group consists of Anadarko Petroleum Corporation, Apache Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., Concho Resources Inc., Continental Resources Inc., Denbury Resources Inc., Devon Energy Corporation, EOG Resources, Inc., EQT Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Co., QEP Resources, Inc., Range Resources Corporation, Sandridge Energy, Inc., SM Energy Company, Ultra Petroleum Corp., Whiting Petroleum Corporation and WPX Energy, Inc. The chart assumes that the value of the investment in our common stock and each index was $100 at December 31, 2011, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance:



	12/31/11	12/31/12	12/31/13	12/31/14	12/31/15	**12/31/16**
Southwestern Energy Company	$ 100	$ 105	$ 123	$ 85	$ 22	**$ 34**
S&P 500 Index	100	116	154	175	177	**198**
Peer Group	100	98	130	110	73	**106**

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, 2016. 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."

	2016	2015	2014	2013	2012
	(in millions except shares, per share, stockholder data and percentages)				
Financial Review					
Operating revenues:					
Exploration and production	$ 1,413	$ 2,074	$ 2,862	$ 2,404	$ 1,964
Midstream services	2,569	3,119	4,358	3,347	2,363
Other	–	–	–	–	3
Intersegment revenues	(1,546)	(2,060)	(3,182)	(2,380)	(1,600)
	2,436	3,133	4,038	3,371	2,730
Operating costs and expenses:					
Marketing purchases – midstream services	864	852	980	782	592
Operating and general and administrative expenses	839	935	648	519	420
Restructuring charges	78	–	–	–	–
Depreciation, depletion and amortization	436	1,091	942	787	811
Impairment of natural gas and oil properties	2,321	6,950	–	–	1,940
Gain on sale of assets, net	–	(283)	–	–	–
Taxes, other than income taxes	93	110	95	79	68
	4,631	9,655	2,665	2,167	3,831
Operating income (loss)	(2,195)	(6,522)	1,373	1,204	(1,101)
Interest expense, net	88	56	59	42	35
Gain (loss) on derivatives	(339)	47	139	26	(15)
Loss on early extinguishment of debt	(51)	–	–	–	–
Other income (loss), net	1	(30)	(4)	2	1
Income (loss) before income taxes	(2,672)	(6,561)	1,449	1,190	(1,150)
Provision (benefit) for income taxes:					
Current	(7)	(2)	21	(11)	19
Deferred	(22)	(2,003)	504	497	(462)
	(29)	(2,005)	525	486	(443)
Net income (loss)	(2,643)	(4,556)	924	704	(707)
Mandatory convertible preferred stock dividend	108	106	–	–	–
Net income (loss) attributable to common stock	$ (2,751)	$ (4,662)	$ 924	$ 704	$ (707)
Net cash provided by operating activities	$ 498	$ 1,580	$ 2,335	$ 1,909	$ 1,654
Net cash used in investing activities	$ (162)	$ (1,638)	$ (7,288)	$ (2,216)	$ (1,907)
Net cash provided by financing activities	$ 1,072	$ 20	$ 4,983	$ 277	$ 291
Common Stock Statistics					
Earnings per share:					
Net income (loss) attributable to common stockholders – Basic	$ (6.32)	$ (12.25)	$ 2.63	$ 2.01	$ (2.03)
Net income (loss) attributable to common stockholders – Diluted	$ (6.32)	$ (12.25)	$ 2.62	$ 2.00	$ (2.03)
Book value per average diluted share	$ 2.11	$ 6.00	$ 13.23	$ 10.32	$ 8.71
Market price at year-end	$ 10.82	$ 7.11	$ 27.29	$ 39.33	$ 33.41
Number of stockholders of record at year-end	3,292	3,415	3,271	3,259	3,122
Average diluted shares outstanding	435,337,402	380,521,039	352,410,683	351,101,452	348,610,503

	2016	2015	2014	2013	2012
Capitalization (in millions)					
Total debt	$ 4,653	$ 4,705	$ 6,957	$ 1,940	$ 1,657
Total equity	917	2,282	4,662	3,622	3,036
Total capitalization	$ 5,570	$ 6,987	$ 11,619	$ 5,562	$ 4,693
Total assets	$ 7,076	$ 8,086	$ 14,915	$ 8,037	$ 6,726
Capitalization ratios:					
Debt	84%	67%	60%	35%	35%
Equity	16%	33%	40%	65%	65%
Capital Investments (in millions) (1)					
Exploration and production	623	2,258	7,254	2,052	1,861
Midstream services	21	167	144	158	165
Other	4	12	49	25	55
	$ 648	$ 2,437	$ 7,447	$ 2,235	$ 2,081
Exploration and Production					
Natural gas:					
Production, Bcf	788	899	766	656	565
Average realized price per Mcf, including derivatives	$ 1.64	$ 2.37	$ 3.72	$ 3.65	$ 3.44
Average realized price per Mcf, excluding derivatives	$ 1.59	$ 1.91	$ 3.74	$ 3.17	$ 2.34
Oil:					
Production, MBbls	2,192	2,265	235	138	83
Average realized price per barrel	$ 31.20	$ 33.25	$ 79.91	$ 103.32	$ 101.54
NGL:					
Production, MBbls	12,372	10,702	231	50	–
Average realized price per barrel	$ 7.46	$ 6.80	$ 15.72	$ 43.63	$ –
Total production, Bcfe	875	976	768	657	565
Lease operating expenses per Mcfe	$ 0.87	$ 0.92	$ 0.91	$ 0.86	$ 0.80
General and administrative expenses per Mcfe (2)	$ 0.22	$ 0.21	$ 0.24	$ 0.24	$ 0.26
Taxes, other than income taxes per Mcfe (3)	$ 0.10	$ 0.10	$ 0.11	$ 0.10	$ 0.10
Proved reserves at year-end:					
Natural gas, Bcf	4,866	5,917	9,809	6,974	4,017
Oil, MMBbls	10.5	8.8	37.6	0.4	0.2
NGLs, MMBbls	53.9	40.9	118.7	–	–
Total reserves, Bcfe	5,253	6,215	10,747	6,976	4,018
Midstream Services					
Volumes marketed, Bcfe	1,062	1,127	904	786	676
Volumes gathered, Bcf	601	799	963	900	846

(1) Capital investments include an increase of $43 million for 2016, a decrease of $33 million for 2015, an increase of $155 million for 2014, and decreases of $25 million and $37 million for 2013 and 2012, respectively, related to the change in accrued expenditures between years.

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

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

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

Management's Discussion and Analysis is the Company's analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the Company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. 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, oil and NGL exploration, development and production, which we refer to as "E&P." We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as "Midstream Services." We conduct most of our businesses through subsidiaries and we operate principally in two segments: E&P and Midstream Services. Currently we operate only in the United States.

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

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, beginning in 2015 and continuing through 2016, 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 to develop our properties. The current commodity price environment has resulted in the impairment of a significant portion of our natural gas and oil properties over recent reporting periods. Commodity prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas, oil or NGLs due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources, impact supply and demand, which in turn determines the sales prices for our production. 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. Our 2016 results also reflect reduced costs of third-party services we were able to negotiate during the downturn in the industry. As industry activity increases, demand for these services also increases, and these service providers are likely to seek higher prices than we were able to obtain in 2016.

Beginning in the fourth quarter of 2015, we decreased activity in the Appalachian Basin and the Fayetteville Shale as a result of the lower commodity price environment. During the first half of 2016, we took steps to refocus the Company through a 40% reduction in our workforce, executive management restructuring and a commitment to strengthen our balance sheet by addressing potential near-term liquidity challenges, as we waited for commodity prices to recover. With the successful implementation of our debt reduction strategy, along with improving forward pricing, we began increasing our activity in the third quarter of 2016, and expect to continue these operations in 2017. During the second half of 2016, we increased our hedging activity designed to assure certain desired levels of cash flow.

Recent Financial and Operating Results

In 2016, our net loss attributable to common stock was $2,751 million, or ($6.32) per diluted share, a decrease from a net loss of $4,662 million, or ($12.25) per diluted share, in 2015. Our net income was $924 million, or $2.62 per diluted share, in 2014. We incurred non-cash impairments of our natural gas and oil properties totaling $2,321 million, or $1,444 million net of taxes, in 2016 and $6,950 million, or $4,287 million net of taxes, in 2015, which resulted primarily from the significant decline in natural gas prices.

In 2016, our natural gas and liquids production totaled 875 Bcfe, a decrease of 10% from 976 Bcfe in 2015. The 101 Bcfe decrease in our 2016 production resulted from a 96 Bcfe decrease in net production from our Fayetteville Shale and other properties and a 10 Bcf decrease in net production from our Northeast Appalachia properties, partially offset by a 5 Bcfe increase in net production from our Southwest Appalachia properties. The reductions resulted primarily from the suspension of drilling activities in the first half of 2016. Our 2015 total natural gas and liquids production of 976 Bcfe increased 27% 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 partially offset by a 38 Bcfe decrease in net production from our Fayetteville Shale and other properties.

Our year-end reserves decreased 15% in 2016 to 5,253 Bcfe from 6,215 Bcfe at the end of 2015 and 10,747 Bcfe at the end of 2014. The overall decrease in total estimated proved reserves in 2016 was primarily due to production and downward price revisions associated with decreased commodity prices, partially offset by upward performance revisions in Northeast and Southwest Appalachia and the Fayetteville Shale. The overall decrease in total estimated proved reserves in 2015 was primarily due to downward revisions associated with decreased commodity prices, partially offset by upward performance revisions in Northeast and Southwest Appalachia.

Our E&P segment operating loss was $2,404 million in 2016, a decrease from an operating loss of $7,104 million in 2015. The operating loss in 2016 included non-cash impairments of natural gas and oil properties totaling $2,321 million. Excluding the non-cash impairments, our E&P segment operating loss decreased to $83 million in 2016 from $154 million in 2015 as the $732 million decrease in operating costs and expenses and $19 million increase in NGL revenues was only partially offset by a 31%, or $0.73 per Mcf, decrease in our average realized natural gas price, a 12%, or 111 Bcf, decrease in natural gas production and a $7 million decrease in oil revenues. Our E&P segment operating loss was $7,104 million in 2015, a decrease from operating income of $1,013 million in 2014. 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. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $27 million in operating income for the year ended December 31, 2014.

Operating income for our Midstream Services segment was $209 million in 2016, a decrease from $583 million in 2015 and $361 million in 2014. Operating income in 2015 includes a $277 million net gain related to the sale of our northeast Pennsylvania and East Texas gathering assets. Excluding the gain on sales, our Midstream Services segment operating income decreased $97 million primarily due to decreased volumes gathered and decreased marketing margin, partially offset by a $32 million decrease in operating costs and expenses, exclusive of marketing purchase costs. Volumes gathered decreased to 601 Bcf in 2016, compared to 799 Bcf in 2015. Excluding the gain on sales, operating income for our Midstream Services segment decreased in 2015 primarily due to a $71 million decrease in gathering revenues, which resulted from decreased volumes gathered, partially offset by a $13 million decrease in operating costs and expenses, exclusive of marketing purchase costs. Volumes gathered decreased to 799 Bcf in 2015, compared to 963 Bcf in 2014. In the second quarter of 2015, we sold our northeastern Pennsylvania and East Texas gathering assets that accounted for $13 million and $35 million in operating income for the years ended December 31, 2015 and 2014, 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.

We had total capital investments of $648 million in 2016, compared to $2.4 billion in 2015 and $7.4 billion in 2014. Of our total capital investments for 2016, $623 million was invested in our E&P segment, which included $152 million related to capitalized interest and $87 million in capitalized expenses. Of our total capital investments in 2015, $2.3 billion was invested in our E&P segment, which included $533 million related to acquisitions from WPX Energy, Inc. ("WPX" with acquisition called the "WPX Property Acquisition") and Statoil ASA ("Statoil" with the acquisition called "Statoil Property Acquisition"), 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"). Our Midstream Services capital investments for 2015 included $109 million related to the WPX Property Acquisition.

Outlook

We expect to continue to exercise capital discipline by aligning our 2017 capital investing program with our expected cash flow from operations and the remaining funds from our equity offering and sale of West Virginia assets. We will also look for opportunities to further strengthen our balance sheet, maximize margins in each core area of our business and further develop our knowledge of our asset base. We believe that 2017 will continue to be a challenging year for our business due to the commodity price environment and continued uncertainty of natural gas, oil and NGL prices in the United States. However, we expect that our resource base, financial flexibility and disciplined investment of capital will position us for success in the current environment and any improvements thereto.

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,		
	2016	2015	2014
Revenues (in millions)	**$ 1,413**	$ 2,074	$ 2,862
Impairment of natural gas and oil properties (in millions)	**$ 2,321**	$ 6,950	$ –
Operating costs and expenses (in millions) (1)	**$ 1,496**	$ 2,228	$ 1,849
Operating income (loss) (in millions)	**$ (2,404)**	$ (7,104)	$ 1,013
Gain on derivatives, settled (in millions) (2)	**$ 36**	$ 206	$ 9
Gas production (Bcf)	**788**	899	766
Oil production (MBbls)	**2,192**	2,265	235
NGL production (MBbls)	**12,372**	10,702	231
Total production (Bcfe)	**875**	976	768
Average realized gas price per Mcf, including derivatives (3)	**$ 1.64**	$ 2.37	$ 3.72
Average realized gas price per Mcf, excluding derivatives	**$ 1.59**	$ 1.91	$ 3.74
Average realized oil price per Bbl	**$ 31.20**	$ 33.25	$ 79.91
Average realized NGL price per Bbl	**$ 7.46**	$ 6.80	$ 15.72
Average unit costs per Mcfe:			
Lease operating expenses	**$ 0.87**	$ 0.92	$ 0.91
General & administrative expenses (4)	**$ 0.22**	$ 0.21	$ 0.24
Taxes, other than income taxes (5)	**$ 0.10**	$ 0.10	$ 0.11
Full cost pool amortization	**$ 0.38**	$ 1.00	$ 1.10

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

(2) Represents the gain (loss) on settled commodity derivatives.

(3) Includes the gain (loss) on settled commodity derivatives.

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

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

Revenues

Revenues for our E&P segment were $1,413 million in 2016, a decrease of 32% compared to 2015. Revenues decreased by $248 million as a result of decreased realized natural gas pricing, excluding the effects of derivatives, $212 million as a result of decreased natural gas production, $209 million as a result of decreased derivative settlement proceeds, $7 million as a result of decreased oil production and realized price and $4 million as a result of decreased other operating revenue. These decreases were partially offset by an increase of $19 million in NGL sales resulting from increased production and realized price. Revenues for our E&P segment were $2,074 million in 2015, a decrease of 28% 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 net NGL and oil production related to our Southwest Appalachia property acquisition partially offset by a $201 million decrease due to decreased net NGL and oil pricing. Natural gas, oil and NGL prices are difficult to predict and are subject to wide price fluctuations. We refer you to Note 4 to the consolidated financial statements included in this Annual Report and to the discussion of "Commodity Prices" provided below for additional information. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $15 million and $70 million of our gas and oil revenues for the years ended December 31, 2015 and 2014, respectively.

Production

In 2016, our natural gas and liquids production totaled 875 Bcfe, a 10% decrease from 976 Bcfe in 2015, and was produced entirely by our properties in the United States. The 101 Bcfe decrease was primarily due to a 96 Bcfe decrease in net production from our Fayetteville Shale and other properties and a 10 Bcf decrease in net production from our Northeast Appalachia properties, partially offset by a 5 Bcfe increase in net production from our Southwest Appalachia properties. Net production from our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale properties was 350 Bcf, 148 Bcfe and 375 Bcf, respectively, for the year ended 2016, compared to 360 Bcf, 143 Bcfe, and 465 Bcf, respectively, for 2015. The reductions resulted primarily from the suspension of drilling activities in the first half of 2016. Our 2015 total natural gas and liquids production of 976 Bcfe increased 27% from 768 Bcfe in 2014, and was also 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 and a 106 Bcf increase in net production from our Northeast Appalachia properties, partially offset by a 38 Bcfe decrease in net production in our Fayetteville Shale and other properties. Net production for 2014 from our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale properties was 254 Bcf, 3 Bcfe and 494 Bcf, respectively.

Natural gas accounted for approximately 90%, 92% and 100% of our total production for the years ended December 31, 2016, 2015 and 2014, respectively. Oil accounted for 2% and 1% of our total production for the years ended December 31, 2016 and 2015, respectively. NGLs accounted for 8% and 7% of our total production for the years ended December 31, 2016 and 2015, respectively.

Our ability to identify, 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, oil and NGL prices and competition. There are also many risks inherent in the discovery, development and production of natural gas, oil and NGLs. 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, after the effects of derivatives, decreased 31% to $1.64 per Mcf in 2016, compared to a decrease of 36% to $2.37 per Mcf in 2015 from 2014 levels. The decrease in 2016 was the result of a $0.32 per Mcf decrease in the average natural gas price, excluding derivatives, and lower proceeds from our hedging program in 2016 as compared to 2015. The decrease in 2015 was the result of a $1.83 per Mcf decrease in the average natural gas price, excluding derivatives, partially offset by higher proceeds from our hedging program in 2015 as compared to 2014. In 2016, our derivatives increased the average natural gas price we realized by $0.05 per Mcf, compared to an increase of $0.46 per Mcf in 2015 and a decrease of $0.02 per Mcf in 2014.

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

In 2016, the average price received, excluding the impact of derivatives, for our natural gas production was $1.59 per Mcf, approximately $0.87 per Mcf lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation costs. We protected approximately 38% of our natural gas production in 2016 from the impact of widening basis differentials through our sales arrangements and financial derivatives. For the year ended December 31, 2016, we protected the basis differentials on approximately 277 Bcf and 78 Bcf of our 2017 and 2018 expected natural gas production through physical sales arrangements and financial derivatives at a basis differential to NYMEX natural gas prices of approximately ($0.50) per Mcf and ($0.34) per Mcf for 2017 and 2018, respectively. We refer you to Note 4 of the consolidated financial statements included in this Annual Report for additional details about our derivative instruments.

Our 2016 average realized sales price of $31.20 per barrel for our oil production decreased approximately 6% from the prior year. The 2015 average realized price of $33.25 per barrel decreased 58% from 2014. We did not use derivatives to financially protect our 2016, 2015 or 2014 oil production.

Our 2016 average realized sales price of $7.46 per barrel for our NGL production increased approximately 10% from the prior year. The 2015 average realized price of $6.80 per barrel decreased 57% from 2014. We did not use derivatives to financially protect our 2016, 2015 or 2014 NGL production.

Operating Income

Our E&P segment operating loss was $2,404 million in 2016, a decrease from an operating loss of $7,104 million in 2015. The E&P segment recorded a $2,321 million impairment of natural gas and oil properties for the year ended December 31, 2016, compared to a $6,950 million impairment for the same period in 2015. Excluding impairments, our E&P segment reported an operating loss of $83 million for the year ended December 31, 2016, compared to an operating loss of $154 million for the same period in 2015, primarily due to a $732 million decrease in operating costs and expenses, consisting of a $657 million decrease in depreciation, depletion and amortization, a $138 million decrease in operating expenses and a $12 million decrease in taxes other than income, partially offset by a $69 million increase in general and administrative expenses and a $6 million decrease in gain on sale of assets, net. General and administrative expenses included $83 million related to restructuring and other one-time charges. Taxes other than income taxes included $3 million related to restructuring charges. Additionally, there was a $19 million increase in NGL revenues resulting from increased production and realized price. The benefits of a net decrease in operating costs and expenses were largely offset by a 31%, or $0.73 per Mcf, decrease in our realized natural gas price, after the effect of derivatives, a 111 Bcf decrease in natural gas production and decreased oil revenues due to decreased production and realized price.

Our E&P segment operating loss was $7,104 million in 2015, a decrease from an operating income of $1,013 million in 2014. The E&P segment recorded a $6,950 million impairment of natural gas and oil properties for the year ended December 31, 2015. There was no impairment recorded in 2014. Excluding the impairments, our E&P segment reported an operating loss of $154 million for the year ended December 31, 2015 compared to an operating income of $1,013 million for the same period in 2014, primarily due to a 36%, or $1.35, decrease in our realized natural gas price, including derivatives, and a $379 million increase in operating costs and expenses that resulted from our production growth, partially offset by a 27%, or 208 Bcfe, increase in production. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin, which accounted for $27 million of our operating income for the year ended December 31, 2014.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.87 in 2016, compared to $0.92 in 2015 and $0.91 in 2014. Lease operating expenses per Mcfe decreased in 2016 compared to 2015 primarily due to successful renegotiations of our existing gathering and processing rates in our Southwest Appalachia operations and decreased workover activity and contract services. As industry activity increases, demand for third-party services also increases, and these service providers are likely to seek higher prices than we were able to obtain in 2016. Lease operating expenses per unit of production increased in 2015 compared to 2014 primarily due to an increase in gathering and compression charges in our Southwest Appalachia operations.

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 was substantially complete by the end of the first quarter of 2016. Excluding the restructuring charges associated primarily with our workforce reduction and other one-time charges, general and administrative expenses for the E&P segment increased to $0.22 per Mcfe in 2016 compared to $0.21 per Mcfe in 2015 and $0.24 per Mcfe in 2014. The 2016 increase was a result of decreased production volumes. In total, excluding the restructuring and other one-time charges, general and administrative expenses for the E&P segment were $193 million for the year ended December 31, 2016 compared to $207 million in 2015 and $182 million in 2014. Including the restructuring and other one-time charges, general and administrative costs for year ended December 31, 2016 were $276 million for our E&P segment. The decrease in general and administrative costs excluding the restructuring and other one-time charges was primarily the result of decreased headcount due to the reduction in workforce and decreased discretionary spending. 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. Our E&P employees decreased by 930 during 2016 compared to a decrease of 155 in 2015. The decrease in 2016 was the result of the 40% workforce reduction during the first quarter as a result of lower anticipated drilling activity.

Taxes other than income taxes per Mcfe were $0.10, $0.10 and $0.11 in 2016, 2015 and 2014, respectively, excluding $3 million related to restructuring charges in 2016. Taxes other than income taxes per Mcfe vary from period to period due to changes in ad valorem and severance taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged $0.38 per Mcfe for 2016, $1.00 per Mcfe for 2015 and $1.10 per Mcfe for 2014. The decreases in the average amortization rates resulted primarily from our full cost ceiling impairments over the respective periods. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling impairments, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserve changes.

Unevaluated costs excluded from amortization were $2.1 billion, $3.7 billion and $4.6 billion at December 31, 2016, 2015 and 2014, respectively. The decrease in unevaluated costs primarily resulted from the evaluation of a portion of our Southwest Appalachia assets of which 55,000 net acres were sold to Antero Resources Corporation during the third quarter of 2016, along with the evaluation of a portion of our New Venture assets. See "Supplemental Oil and Gas Disclosures" in Item 8 of Part II of this Annual Report for additional information regarding our unevaluated costs excluded from amortization.

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,					
	2016		2015		2014	
	($ in millions, except volumes)					
Marketing revenues	**$**	**2,191**	$	2,628	$	3,797
Gas gathering revenues	**$**	**378**	$	491	$	562
Marketing purchases	**$**	**2,145**	$	2,566	$	3,738
Operating costs and expenses (1)	**$**	**215**	$	247	$	260
Gain on sale of assets, net	**$**	**–**	$	277	$	–
Operating income	**$**	**209**	$	583	$	361
Volumes marketed (Bcfe)		**1,062**		1,127		904
Volumes gathered (Bcf)		**601**		799		963

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

Revenues

Revenues from our marketing activities decreased 17% to $2.2 billion for 2016 compared to 2015 due to a 12% decrease in the average price received for volumes marketed and a 6% decrease in volumes marketed. Revenues from our marketing activities decreased 31% to $2.6 billion for 2015 compared to 2014 primarily due to a 45% decrease in the average price received for volumes marketed, partially offset by a 25% increase in volumes marketed. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in marketing purchase expenses. Of the total natural gas volumes marketed, production from our affiliated E&P operated wells accounted for 93% in 2016, 97% in 2015 and 97% in 2014. Our Midstream Services segment marketed approximately 65% and 60% of our combined oil and NGL production for the years ended December 31, 2016 and 2015, respectively.

Revenues from our gathering activities decreased 23% to $378 million for 2016 compared to 2015, primarily from a 25% decrease in natural gas volumes gathered in 2016. The decrease in gathering revenues for 2016 was primarily due to decreased volumes in the Fayetteville Shale and the divestiture of our northeastern Pennsylvania and East Texas gathering assets in 2015. Revenues from our gathering activities decreased 13% to $491 million for 2015 compared to 2014, primarily due to a 17% decrease in natural gas volumes gathered in 2015. The decrease in gathering revenues for 2015 was primarily due to the divestiture of our northeastern Pennsylvania and East Texas gathering assets in 2015. The divested gathering assets accounted for $21 million and $67 million of our gathering revenues for the years ended December 31, 2015 and 2014, respectively.

Operating Income

Operating income from our Midstream Services segment decreased to $209 million in 2016 and increased to $583 million in 2015, compared to the prior year. The decrease in operating income in 2016 is primarily due to a $277 million net gain on sale of assets in 2015 related to the sale of our northeastern Pennsylvania and East Texas gathering assets. Excluding the net gain on sale, operating income decreased 32% to $209 million in 2016 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. Decreases of $113 million in gas gathering revenues and $16 million in marketing margin were partially offset by a $32 million decrease in operating costs and expenses. Excluding the net gain on sale, our Midstream Services segment operating income decreased 15% to $306 million in 2015 due to a decrease in volumes gathered resulting from lower production volumes in the Fayetteville Shale and the absence of income from the northeastern Pennsylvania and East Texas gathering assets that we sold. A decrease of $71 million in gas gathering revenues was partially offset by a $13 million decrease in operating costs and expenses and a $3 million increase in marketing margin. The divested gathering assets accounted for $13 million and $35 million of our operating income for the years ended December 31, 2015 and 2014, respectively.

The margin generated from marketing activities was $46 million for 2016, compared to $62 million for 2015 and $59 million for 2014. Margins are driven primarily by volumes marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. We enter into derivative contracts from time to time with respect to our natural gas marketing activities to provide margin protection. For more information about our derivatives and risk management activities, we refer you to Item 7A of Part II of this Annual Report and Note 4 to the consolidated financial statements.

Restructuring Charges

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

Interest Expense

Interest expense, net of capitalization, was $88 million in 2016, compared to $56 million in 2015 and $59 million in 2014. Gross interest expense increased to $240 million in 2016 from $213 million in 2015, excluding a $47 million charge for unamortized fees associated with the repayment of our bridge facility in the first quarter of 2015, due to an increase in our cost of debt. Gross interest expense for 2016 includes $6 million related to unamortized debt issuance costs and debt discounts associated with the extinguished debt. Capitalized interest decreased to $152 million in 2016, compared to $204 million in 2015 primarily due to the evaluation of a portion of our Southwest Appalachia assets acquired in December 2014. Gross interest expense increased 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.

Gain (Loss) on Derivatives

In general, our derivatives are not designated for hedge accounting treatment. Changes in the fair value of derivatives that are not designated for hedge accounting are recorded in gain (loss) on derivatives. We recorded a $339 million net loss on our derivatives for the year ended December 31, 2016, consisting of a $373 million loss on unsettled derivatives, partially offset by a $34 million gain on settled derivatives. We recorded a $47 million net gain on our derivatives for the year ended December 31, 2015, consisting of a $202 million gain on settled derivatives, partially offset by a $155 million loss on unsettled derivatives. We refer you to Note 4 to the consolidated financial statements included in the Annual Report for additional details about our gain (loss) on derivatives. In general and without consideration of volatility or duration, as natural gas prices increase from December 31, 2016 levels, we will recognize losses in future periods and, likewise, as natural gas prices decline from December 31, 2016 levels, we will recognize gains in future periods on our derivative contracts not designated for hedge accounting treatment prior to settlement.

Loss on Early Extinguishment of Debt

During the third quarter of 2016, we used a portion of the proceeds from our July 2016 equity offering to purchase and retire $700 million of our outstanding senior notes due in the first quarter of 2018 and retire $375 million of our $750 million term loan entered into in November 2015. For the year ended December 31, 2016, we recognized a loss of $51 million for the redemption of these senior notes, which included $50 million of premiums paid. Unamortized debt issuance costs and debt discounts associated with the extinguished debt totaled $6 million and were included in other interest charges for the year ended December 31, 2016. In September 2016, we used $48 million of the proceeds received from the West Virginia sale to Antero Resources Corporation to further decrease the balance of the term loan entered into in November 2015.

Income Taxes

Our effective tax rate was approximately 1%, 31%, and 36%, in 2016, 2015 and 2014, respectively. We recorded an income tax benefit of $29 million and $2,005 million in 2016 and 2015, respectively, and income tax expense of $525 million in 2014. Our effective tax rate decreased as a result of our recognition of a valuation allowance (beginning in the fourth quarter of 2015 and persisting throughout 2016) that reduced the deferred tax asset primarily related to our current net operating loss carryforward. A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. We refer you to Note 9 to the consolidated financial statements for additional discussion about our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on funds generated from our operations, our cash and cash equivalents balance, our $809 million revolving credit facilities and capital markets as our primary sources of liquidity.

During 2016, we took significant steps in managing our maturities and liquidity. In June 2016, we refinanced approximately 97% of our principal credit facility, which was due in December 2018, including extending the maturity by two years until December 2020, granting liens on certain assets and modifying interest rates and covenants. We simultaneously modified interest rates and covenants under our $750 million unsecured term loan facility and provided for its extension to December 2020 should its principal balance be reduced by 50% by June 2018. The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least $765 million of our senior notes due in January 2020. In July 2016, we completed a public offering of 98,900,000 shares of our common stock, with net proceeds totaling approximately $1,247 million after underwriting discounts and offering expenses. Of the funds received from the common stock offering, $375 million was used to pay down a portion of our $750 million unsecured term loan and $750 million was used to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of our outstanding senior notes due in the first quarter of 2018. The repayment of $375 million on the $750 million unsecured term loan had the effect of extending its maturity date to December 2020, subject to the conditions described above. In September 2016, we completed the sale of 55,000 net acres in West Virginia for $422 million to Antero Resources Corporation, subject to customary post-closing adjustments, and used $48 million of the proceeds to further decrease the balance of this term loan. We earmarked $500 million of the remaining funds from the equity issuance and the sale of the West Virginia acreage for capital activity, with approximately $300 million having been invested as of December 31, 2016.

During the first half of 2016, we suspended drilling and completion activity in the Appalachian Basin and Fayetteville Shale as a result of the commodity price environment. After the successful implementation of our debt reduction strategy and our equity offering, we began increasing our activity in the third quarter of 2016, which continued throughout the remainder of the year. Although we have the financial flexibility to draw on the funds available under our cash balance and revolving credit facility as necessary, we continue to be committed to our capital discipline strategy of investing within our cash flow from operations, supplemented by the remaining funds from the July 2016 equity issuance and asset sale in West Virginia. We refer you to Note 7 of the consolidated financial statements included in this Annual Report and the section below under "Financing Requirements" for additional discussion of our credit facilities.

The credit status of the financial institutions participating in our revolving credit facilities could adversely impact our ability to borrow funds under the revolving credit facilities. Although we believe all of the lenders under the facilities have the ability to provide funds, we cannot predict whether each will be able to meet their obligation to us. We refer you to the section below under "Financing Requirements" for additional discussion of our compliance with the covenants of our term loans and revolving credit facilities.

Net cash provided by operating activities decreased to $0.5 billion in 2016, down 69% from $1.6 billion in 2015, primarily due to decreased natural gas prices and production. Net cash provided by operating activities decreased to $1.6 billion in 2015, down 32% from $2.3 billion in 2014 primarily due to decreased natural gas prices. Net cash generated from operating activities provided 77% of our cash requirements for capital investments in 2016, reflecting our commitment to our capital discipline strategy of investing within our cash flow from operations, supplemented by the recent equity issuance and asset sales, during the current commodity price environment. Net cash generated from operating activities provided 66% of our cash requirements for capital investments, including acquisitions, in 2015 and 31% in 2014.

Our cash flow from operating activities is highly dependent upon the sales prices that we receive for our natural gas and liquids production. Natural gas, oil and NGL prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. The sales price we receive for our production is also influenced by our commodity hedging activities. See "Risk Factors" in Item 1A, "Quantitative and Qualitative Disclosures about Market Risks" in Item 7A and Note 4, "Derivatives and Risk Management" in the consolidated financial statements for further details. Our 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 joint interest partners. We actively manage this risk through credit management activities and, through the date of this filing, have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and joint interest partners could adversely impact our cash flows.

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

Capital Investments

Our capital investments were $648 million, $2.4 billion and $7.4 billion in 2016, 2015 and 2014, respectively. Capital investments include an increase of $43 million in 2016, a decrease of $33 million in 2015 and an increase of $155 million in 2014 related to the change in accrued expenditures between years. Our E&P segment investments in 2016 were $623 million, compared to $2.3 billion in 2015, which included $533 million, in total, relating to the WPX and Statoil Property Acquisitions, and $7.3 billion in 2014, which included $5.2 billion primarily related to the Chesapeake Property Acquisition. Our E&P segment capitalized internal costs of $112 million for the year ended December 31, 2016 compared to $307 million and $320 million in 2015 and 2014, respectively. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties. Our Midstream Services capital investments for 2015 excludes $109 million related to the WPX Property Acquisition that is recognized in "Acquisitions" in the table below:

	Capital investments for the years ended December 31,		
	2016	2015	2014
		(in millions)	
Exploration and production	**$ 623**	$ 1,725	$ 2,021
Acquisitions	**–**	642	5,233
Midstream Services	**21**	58	144
Other	**4**	12	49
	$ 648	$ 2,437	$ 7,447

The remaining funds, after debt reduction, from the equity issuance and West Virginia acreage sale enabled us to supplement our 2016 capital budget, allowing us the opportunity to complete many of our drilled but uncompleted wells and resume drilling on our high PVI projects.

Financing Requirements

Our total debt outstanding was $4.7 billion as of December 31, 2016 and December 31, 2015. Our total debt, net of cash and cash equivalents of $1.4 billion, was $3.2 billion at December 31, 2016, compared to $4.7 billion at December 31, 2015. Our actions to reduce and extend our total debt outstanding are further discussed below.

At February 21, 2017, we had a long-term issuer credit rating of Ba3 by Moody's, a long-term debt rating of BB- by S&P and a long-term issuer default rating of BB by Fitch Ratings. Any downgrades in our public debt ratings by Moody's or S&P could increase our cost of funds and decrease our liquidity under our revolving credit facilities.

At December 31, 2016, our capital structure consisted of 84% debt (excluding $1.4 billion in cash and cash equivalents) and 16% equity, compared to 67% debt (excluding $15 million in cash and cash equivalents) and 33% equity at December 31, 2015. This increase was due principally to a 59% decrease in shareholders equity, resulting primarily from non-cash ceiling test impairments.

In July 2016, we consummated an underwritten offering of 98,900,000 shares of our common stock pursuant to an effective registration statement filed with the Securities and Exchange Commission, with net proceeds of the offering totaling approximately $1,247 million after underwriting discounts and offering expenses. A portion of the proceeds from the offering were used to repay $375 million of the $750 million term loan entered into in November 2015 and to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of our outstanding senior notes due in the first quarter of 2018. The remaining net proceeds of the offering will be used for general corporate purposes, including the completion of wells already drilled or the funding of other capital projects.

In June 2016, we reduced our existing $2.0 billion unsecured revolving credit facility to $66 million and entered into a new credit agreement for $1,934 million, consisting of a $1,191 million secured term loan and a new unsecured $743 million revolving credit facility, which matures in December 2020. The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least $765 million of our senior notes due in January 2020. The $1,191 million secured term loan is fully drawn, with approximately $285 million of this balance used to pay down the existing revolving credit facility balance in its entirety. As of December 31, 2016, there were no borrowings under either revolving credit facility, however, there was $174 million in letters of credit outstanding against the 2016 revolving credit facility.

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

Our 2016 credit agreement contains financial covenants that impose certain restrictions on us. Under our revolving credit and term loan facilities, we must keep a minimum interest coverage of 0.75x in 2016, increasing by 0.25x increments per year to 1.50x in 2019 and 2020. We are also subject to a minimum liquidity requirement of $300 million, which could be increased up to $500 million upon certain conditions, as well as an anti-hoarding provision, requiring unrestricted cash in excess of $100 million to pay down any amounts borrowed under the new revolving credit facility. The financial covenant with respect to minimum interest coverage consists of EBITDAX divided by consolidated interest expense. EBITDAX, as defined in our 2016 credit agreement, excludes the effects of interest expense, income taxes, depreciation, depletion and amortization, any non-cash impacts from impairments, certain non-cash hedging activities, stock-based compensation expense, non-cash gains or losses on asset sales, unamortized issuance cost, unamortized debt discount and certain restructuring costs. Collateral for the new secured term loan is principally our E&P properties in the Fayetteville Shale area, the equity of its subsidiaries and cash and marketable securities on hand. This collateral also may support all or a part of revolving credit extensions depending on restrictions in our senior notes indentures, and requires a minimum collateral coverage ratio of 1.50x.

The existing unsecured 2013 revolving credit facility includes a financial covenant under which we may not issue total debt in excess of 60% of our total adjusted book capital, as defined in that agreement. This financial covenant with respect to capitalization percentages excludes the effects of any full cost ceiling impairments, certain hedging activities and our pension and other postretirement liabilities. We are in compliance with this covenant. As of December 31, 2016, the maximum amount available under this credit facility was $66 million, with no amounts outstanding.

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 existing revolving credit facility. The interest rate on the term loan facility is determined based upon our public debt ratings from Moody's and S&P and was 250 basis points over LIBOR as of December 31, 2016. 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 June 2016, the 2015 term loan agreement was amended to extend the maturity date, provided at least 50% would be paid down by June 2017. After our July 2016 equity offering, we repaid $375 million of the $750 million term loan, which had the effect of extending its maturity from November 2018 to December 2020. The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least $765 million of our 2020 Senior Notes. In September 2016, we repaid an additional $48 million of the term loan with proceeds from the sale of our West Virginia acreage.

As of December 31, 2016, we were in compliance with all of the covenants of the term loans and revolving credit facilities. Although we do not anticipate any violations of the financial covenants, our ability to comply with these covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and liquids.

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. Since inception, and as of February 21, 2017, we have made four of the quarterly dividend payments in cash and four of the dividend payments in common stock. 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 (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 existing 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 are determined based on our public bond ratings from Moody's and S&P. Downgrades on the Notes from either rating agency increase our interest costs by 25 basis points per downgrade level on the following semi-annual bond interest payment. Based on the February and June 2016 downgrades from Moody's and S&P our interest rates on these Notes increased by 175 basis points in July 2016. In July 2016, we used a portion of the proceeds from the July 2016 equity offering to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of our outstanding senior notes due in the first quarter of 2018.

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.

Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. Excluding basis swaps, at February 21, 2017, we had commodity price derivatives in place on 515 Bcf, 272 Bcf and 80 Bcf of our targeted 2017, 2018 and 2019 natural gas production, respectively. We also had commodity derivatives in place on 350 MBbls of our targeted ethane production for 2017 and 2018.

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, 2016, our material off-balance sheet arrangements and transactions include operating lease arrangements and $174 million in letters of credit outstanding against our 2016 revolving credit facility. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. For more information regarding off-balance sheet arrangements, we refer you to "Contractual Obligations and Contingent Liabilities and Commitments" below for more information on our operating leases.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations as of December 31, 2016, were as follows:

Contractual Obligations:

	Payments Due by Period					
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
	(in millions)					
Transportation charges [1]	**$ 8,429**	$ 627	$ 1,484	$ 1,275	$ 1,507	$ 3,536
Debt	**4,684**	41	275	2,368	1,000	1,000
Interest on debt [2]	**1,195**	229	422	289	221	34
Operating leases [3]	**229**	66	97	52	7	7
Compression services [4]	**26**	16	10	–	–	–
Operating agreements	**3**	3	–	–	–	–
Purchase obligations	**33**	33	–	–	–	–
Other obligations [5]	**35**	27	8	–	–	–
	$ 14,634	$ 1,042	$ 2,296	$ 3,984	$ 2,735	$ 4,577

(1) As of December 31, 2016, we had commitments for demand and similar charges under firm transport and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems. Of the total $8.4 billion, 40% related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts.

(2) Interest payments on our senior notes were calculated utilizing the fixed rates associated with our fixed rate notes outstanding at December 31, 2016. Interest payments on the term loan facility were calculated by assuming that the December 31, 2016 outstanding balance of $327 million will be outstanding through the December 2020 maturity date. Interest payments on the term loan facility were calculated by assuming that the December 31, 2016 outstanding balance of $1,191 million will be outstanding through the December 2020 maturity date. A constant rate of 3.22%, the rate as of December 31, 2016, was assumed for the December 2020 term loan facilities. All interest rates were based on our credit ratings as of December 31, 2016.

(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, 2016, our Midstream Services segment had commitments of approximately $24 million and our E&P segment had commitments of approximately $2 million for compression services associated primarily with our Fayetteville and Southwest Appalachia divisions.

(5) Our other significant contractual obligations include approximately $13 million for various information technology support and data subscription agreements.

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

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

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 positive working capital of $808 million as of December 31, 2016 and negative working capital of $314 million at December 31, 2015. The positive working capital as of December 31, 2016 was primarily due to $1.4 billion of cash and cash equivalents resulting from our new term loan, equity offering and proceeds from the sale of our West Virginia acreage. The negative working capital as of December 31, 2015 was primarily due to a decrease in derivative assets in 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.

Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and related capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2016, we had a total of $2,105 million of costs excluded from our amortization base, all of which related to our properties in the United States. Inclusion of some or all of these costs in our properties in the United States in the future, without adding any associated reserves, could result in additional ceiling test impairments.

In the first, second, and third quarters of 2016, the net book value of our United States and Canada natural gas and oil properties exceeded the ceiling by approximately $641 million (net of tax) at March 31, 2016, $297 million (net of tax) at June 30, 2016 and $506 million (net of tax) at September 30, 2016, resulting in non-cash ceiling test impairments in each of those quarters. We had no hedge positions that were designated for hedge accounting as of March 31, 2016, June 30, 2016 and September 30, 2016. Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.48 per MMBtu, West Texas Intermediate oil of $39.25 per barrel and NGLs of $6.74 per barrel, adjusted for market differentials, the net book value of our United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2016. We had no derivative positions that were designated for hedge accounting as of December 31, 2016. Although no ceiling test impairment was recorded in the fourth quarter of 2016, future decreases in commodity prices, increases in costs and/or changes in the balance of costs excluded from amortization and other factors may result in additional impairments to our natural gas and oil properties in 2017.

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 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. 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.

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 for Henry Hub natural gas of $4.35 per MMBtu, for West Texas Intermediate oil of $91.48 per barrel and NGLs of $23.79 per barrel, adjusted for market differentials. The net book value of our natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2014.

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, 2016 was approximately 93% natural gas compared to 95% as of December 31, 2015. In the past, nearly all of our reserve base was natural gas; therefore changes in oil and NGL prices used did not have as significant an impact as natural gas prices on cash flows and reserve quantities. Our standardized measure and reserve quantities as of December 31, 2016, were $1.7 billion and 5.3 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 30 years of experience in petroleum engineering, including the estimation of oil and natural gas reserves, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining us in 2009, our Reservoir Supervisor - Reserves served in various reservoir engineering roles for Citation Oil & Gas Corporation, Mitchell Energy & Development Corporation, White Stone Energy and H.J. Gruy & Associates and is a member of the Society of Petroleum Engineers and Society of Petroleum Evaluation Engineers and is a Licensed Professional Engineer in the state of Texas. He reports to our Planning and Reserves Manager, who has more than 9 years of experience in reservoir engineering including the estimation of natural gas, oil and NGL reserves in multiple basins in the United States and holds a Bachelor of Science in Chemical Engineering and a Master of Business Administration. Prior to joining Southwestern in 2011, our Planning and Reserves Manager served in various engineering roles for BP and is a member of the Society of Petroleum Engineers and IPAA. Our Planning and Reserves Manager reports to our Senior Vice President – Corporate Development, who has more than 22 years of experience in petroleum engineering including the estimation of natural gas, oil and NGL reserves in multiple basins in the United States, and holds a Bachelor of Science in Petroleum Engineering and a Master of Business Administration. Prior to joining Southwestern in 2014, our Senior Vice President – Corporate Development served in various engineering and leadership roles for Quantum Resource Management, Anadarko Petroleum Company, Howell Petroleum and Meridian Oil/Burling Resources and is a member of the Society of Petroleum Engineers and IPSS.

We engage NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates as discussed in more detail below. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the two technical persons primarily responsible for auditing our proved reserves estimates (1) have over 35 years and over 14 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 25 years and over 14 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 99% of our total reserve base as of December 31, 2016. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We refer you to "Our proved natural gas, oil and NGL reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A, "Risk Factors," of Part I of this Annual Report for a more detailed discussion of these uncertainties, risks and other factors.

In conducting its audit, the engineers and geologists of NSAI study our major properties in detail and independently develop reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of major properties that account for approximately 99% of the present worth of the company's total proved reserves. NSAI's audit process consists of sorting all fields by descending present value order and selecting the fields from highest value to descending value until the selected fields account for more than 80% of the present worth of our reserves. The fields included in approximately the top 99% present value as of December 31, 2016, accounted for approximately 98% 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 13, 2017, NSAI issued its audit opinion as to the reasonableness of our reserve estimates for the year-ended December 31, 2016, 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 the WPX and the Statoil Property Acquisitions of certain natural gas and oil assets. 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 6 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.

Derivatives and Risk Management

We use fixed price swap agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of certain commodities and interest rates. Our policies prohibit speculation with derivatives and limit agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. In 2016, 2015, and 2014 we financially protected 28%, 27% and 60% of our natural gas production, respectively, with derivatives. The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas. However, the market price risk is generally offset by the gain or loss recognized upon the related natural gas transaction that is financially protected.

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

As of December 31, 2016, none of our derivative contracts were designated for hedge accounting treatment. During 2016, the Company settled all of its purchased put options, which were not designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated for hedge accounting treatment are recorded in gain (loss) on derivatives. For those derivatives not designated for hedge accounting treatment, we recorded a loss on derivatives of $177 million related to fixed price swaps, a loss on derivatives of $81 million related to sold call options, a loss on derivatives of $80 million related to three-way costless collars and a loss on derivatives of $45 million related to two-way costless collars. These losses were partially offset by a gain on derivatives of $33 million related to basis swaps and a gain on derivatives of $11 million related to purchased put options.

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 11 to the consolidated financial statements for further discussion and disclosures regarding these benefit plans). Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For the December 31, 2016 benefit obligation and periodic benefit cost to be recorded in 2017, the discount rate assumed is 4.20% and 4.20%, respectively. This compares to a discount rate of 4.60% and 4.25% for the benefit obligation and periodic benefit cost recorded in 2016, respectively. For the 2017 periodic benefit cost, the expected return assumed is 7.00%, compared to an expected return of 7.00% in 2016.

Using the assumed rates discussed above, we recorded total benefit cost of $19 million in 2016 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 2016 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, 2016, we recognized a liability of $49 million, compared to $50 million at December 31, 2015, related to our pension and other postretirement benefit plans. During 2016, we also made cash payments totaling $11 million to fund our pension and other postretirement benefit plans.

Asset Retirement Obligations

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

Stock-Based Compensation

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

New Accounting Standards

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

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

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

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

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Credit Risk

Our 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, 2016. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

As of December 31, 2016, we had approximately $3.2 billion of outstanding senior notes with a weighted average interest rate of 5.68%, and $1.5 billion of term loan facility debt with a variable interest rate of 3.22%. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates.

	Expected Maturity Date						
	2017	2018	2019	2020	2021	Thereafter	**Total**
Fixed Rate Payments [1] (in millions)	$ 41	$ 275	$ –	$ 850	$ –	$ 2,000	**$ 3,166**
Weighted Average Interest Rate	7.21 %	7.13 %	– %	5.80 %	– %	5.40 %	**5.68 %**
Variable Rate Payments [1] (in millions)	$ –	$ –	$ –	$ 1,518 [2]	$ –	$ –	**$ 1,518**
Weighted Average Interest Rate	– %	– %	– %	3.22 %	– %	– %	**3.22 %**

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

(2) The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least $765 million of our 2020 Senior Notes.

Commodities Risk

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

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

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

Management's Report on Internal Control Over Financial Reporting

It is the responsibility of the management of Southwestern Energy Company to establish and maintain adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2016, utilizing the Committee of Sponsoring Organizations of the Treadway Commission's *Internal Control—Integrated Framework (2013)*.

Based on this evaluation, management has concluded the Company's internal control over financial reporting was effective as of December 31, 2016.

The effectiveness of our internal control over financial reporting as of December 31, 2016 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, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 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, 2016, 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 23, 2017

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the years ended December 31,		
	2016	2015	2014
	(in millions, except share/per share amounts)		
Operating Revenues:			
Gas sales	**$ 1,273**	$ 1,946	$ 2,827
Oil sales	**69**	76	19
NGL sales	**92**	73	3
Marketing	**864**	863	996
Gas gathering	**138**	175	193
	2,436	3,133	4,038
Operating Costs and Expenses:			
Marketing purchases	**864**	852	980
Operating expenses	**592**	689	427
General and administrative expenses	**247**	246	221
Restructuring charges	**78**	–	–
Depreciation, depletion and amortization	**436**	1,091	942
Impairment of natural gas and oil properties	**2,321**	6,950	–
Gain on sale of assets, net	**–**	(283)	–
Taxes, other than income taxes	**93**	110	95
	4,631	9,655	2,665
Operating Income (Loss)	**(2,195)**	(6,522)	1,373
Interest Expense:			
Interest on debt	**226**	200	101
Other interest charges	**14**	60	13
Interest capitalized	**(152)**	(204)	(55)
	88	56	59
Gain (Loss) on Derivatives	**(339)**	47	139
Loss on Early Extinguishment of Debt	**(51)**	–	–
Other Income (Loss), Net	**1**	(30)	(4)
Income (Loss) Before Income Taxes	**(2,672)**	(6,561)	1,449
Provision (Benefit) for Income Taxes:			
Current	**(7)**	(2)	21
Deferred	**(22)**	(2,003)	504
	(29)	(2,005)	525
Net Income (Loss)	**$ (2,643)**	$ (4,556)	$ 924
Mandatory convertible preferred stock dividend	**108**	106	–
Net Income (Loss) Attributable to Common Stock	**$ (2,751)**	$ (4,662)	$ 924
Earnings (Loss) Per Common Share:			
Basic	**$ (6.32)**	$ (12.25)	$ 2.63
Diluted	**$ (6.32)**	$ (12.25)	$ 2.62
Weighted Average Common Shares Outstanding:			
Basic	**435,337,402**	380,521,039	351,446,747
Diluted	**435,337,402**	380,521,039	352,410,683

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,		
	2016	2015	2014
		(in millions)	
Net income (loss)	$ **(2,643)**	$ (4,556)	$ 924
Change in derivatives:			
Settlements [(1)]	**–**	(128)	16
Ineffectiveness	**–**	1	–
Change in fair value of derivative instruments [(2)]	**–**	29	73
Total change in derivatives	**–**	(98)	89
Change in value of pension and other postretirement liabilities:			
Amortization of prior service cost and net loss included in net periodic pension cost [(3)]	**13**	2	–
Net gain (loss) incurred in period [(4)]	**(7)**	(3)	(15)
Total change in value of pension and postretirement liabilities	**6**	(1)	(15)
Change in currency translation adjustment	**3**	(11)	(8)
Comprehensive income (loss)	$ **(2,634)**	$ (4,666)	$ 990

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

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

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

(4) Net of ($4) million and ($10) million in taxes for the years ended December 31, 2016 and 2014, respectively.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
	(in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,423	$ 15
Accounts receivable, net	363	327
Derivative assets	51	3
Other current assets	35	48
Total current assets	1,872	393
Natural gas and oil properties, using the full cost method, including $2,105 million as of December 31, 2016 and $3,727 million as of December 31, 2015 excluded from amortization	22,653	22,478
Gathering systems	1,299	1,280
Other	537	606
Less: Accumulated depreciation, depletion and amortization	(19,534)	(16,821)
Total property and equipment, net	4,955	7,543
Other long-term assets	249	150
TOTAL ASSETS	$ 7,076	$ 8,086
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term debt	$ 41	$ 1
Accounts payable	473	513
Taxes payable	59	64
Interest payable	74	75
Dividends payable	27	27
Derivative liabilities	355	3
Other current liabilities	35	24
Total current liabilities	1,064	707
Long-term debt	4,612	4,704
Pension and other postretirement liabilities	49	50
Other long-term liabilities	434	343
Total long-term liabilities	5,095	5,097
Commitments and contingencies (see Note 8)		
Equity:		
Common stock, $0.01 par value; 1,250,000,000 shares authorized; issued 495,248,369 shares as of December 31, 2016 (does not include 2,751,410 shares issued on January 17, 2017 on account of a dividend declared on December 12, 2016) and 390,138,549 as of December 31, 2015	5	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, 2016 and 2015, conversion in January 2018	–	–
Additional paid-in capital	4,677	3,409
Accumulated deficit	(3,725)	(1,082)
Accumulated other comprehensive loss	(39)	(48)
Common stock in treasury, 31,269 and 47,149 shares as of December 31, 2016 and 2015, respectively	(1)	(1)
Total equity	917	2,282
TOTAL LIABILITIES AND EQUITY	$ 7,076	$ 8,086

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,		
	2016	2015	2014
		(in millions)	
Cash Flows From Operating Activities:			
Net income (loss)	**$ (2,643)**	$ (4,556)	$ 924
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**436**	1,092	942
Impairment of natural gas and oil properties	**2,321**	6,950	–
Amortization of debt issuance costs	**14**	53	10
Deferred income taxes	**(22)**	(2,003)	504
(Gain) loss on derivatives, net of settlement	**373**	155	(130)
Stock-based compensation	**29**	26	18
Gain on sale of assets, net	**–**	(283)	–
Restructuring charges	**30**	–	–
Loss on early extinguishment of debt	**51**	–	
Other	**8**	34	2
Change in assets and liabilities:			
Accounts receivable	**(30)**	203	(66)
Accounts payable	**(69)**	(78)	84
Taxes payable	**(5)**	(28)	24
Interest payable	**–**	9	–
Other assets and liabilities	**5**	6	23
Net cash provided by operating activities	**498**	1,580	2,335
Cash Flows From Investing Activities:			
Capital investments	**(593)**	(1,798)	(2,043)
Acquisitions	**–**	(579)	(5,298)
Proceeds from sale of property and equipment	**430**	729	43
Other	**1**	10	10
Net cash used in investing activities	**(162)**	(1,638)	(7,288)
Cash Flows From Financing Activities:			
Payments on current portion of long-term debt	**(1)**	(1)	(1)
Payments on long-term debt	**(1,175)**	(500)	–
Payments on short-term debt	**–**	(4,500)	–
Payments on revolving credit facility	**(3,268)**	(3,024)	(5,179)
Borrowings under revolving credit facility	**3,152**	2,840	5,196
Payments on commercial paper	**(242)**	(7,988)	–
Borrowings under commercial paper	**242**	7,988	–
Change in bank drafts outstanding	**(20)**	12	11
Proceeds from issuance of long-term debt	**1,191**	2,950	500
Proceeds from issuance of short-term debt	**–**	–	4,500
Debt issuance costs	**(17)**	(20)	(56)
Proceeds from exercise of common stock options	**–**	–	12
Proceeds from issuance of common stock	**1,247**	669	–
Proceeds from issuance of mandatory convertible preferred stock	**–**	1,673	–
Preferred stock dividend	**(27)**	(79)	–
Cash paid for tax withholding	**(9)**	–	–
Other	**(1)**	–	–
Net cash provided by financing activities	**1,072**	20	4,983
Increase (decrease) in cash and cash equivalents	**1,408**	(38)	30
Cash and cash equivalents at beginning of year	**15**	53	23
Cash and cash equivalents at end of year	**$ 1,423**	$ 15	$ 53

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 Shares Issued	Common Stock Amount	Preferred Stock 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, 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 loss:								
Net loss	–	–	–	–	(4,556)	–	–	**(4,556)**
Other comprehensive loss	–	–	–	–	–	(110)	–	**(110)**
Total comprehensive loss	–	–	–	–	–	–	–	**(4,666)**
Stock-based compensation	–	–	–	48	–	–	–	**48**
Preferred stock dividend	–	–	–	–	(106)	–	–	**(106)**
Issuance of common stock	30,000,000	–	–	669	–	–	–	**669**
Issuance of preferred stock	–	–	1,725,000	1,673	–	–	–	**1,673**
Issuance of restricted stock	5,821,125	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(103,162)	–	–	–	–	–	–	**–**
Treasury stock – non-qualified plan	–	–	–	–	–	–	(1)	**(1)**
Tax withholding – stock compensation	(73,869)	–	–	–	–	–	–	**–**
Issuance of stock awards	5,463	–	–	–	–	–	–	**–**
Non-controlling interest	–	–	–	–	3	–	–	**3**
Balance at December 31, 2015	390,138,549	$ 4	1,725,000	$ 3,409	$ (1,082)	$ (48)	$ (1)	**$ 2,282**
Comprehensive loss:								
Net loss	**–**	**–**	**–**	**–**	**(2,643)**	**–**	**–**	**(2,643)**
Other comprehensive income	**–**	**–**	**–**	**–**	**–**	**9**	**–**	**9**
Total comprehensive loss	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(2,634)**
Stock-based compensation	**–**	**–**	**–**	**58**	**–**	**–**	**–**	**58**
Preferred stock dividend (1)	**7,166,389**	**–**	**–**	**(27)**	**–**	**–**	**–**	**(27)**
Exercise of stock options	**44,880**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Issuance of common stock	**98,900,000**	**1**	**–**	**1,246**	**–**	**–**	**–**	**1,247**
Issuance of restricted stock	**87,472**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Cancellation of restricted stock	**(165,483)**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Tax withholding – stock compensation	**(929,252)**	**–**	**–**	**(9)**	**–**	**–**	**–**	**(9)**
Issuance of stock awards	**5,814**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Balance at December 31, 2016	**495,248,369**	**$ 5**	**1,725,000**	**$ 4,677**	**$ (3,725)**	**$ (39)**	**$ (1)**	**$ 917**

(1) Does not include 2,751,410 shares issued on January 17, 2017 and distributed to holders of the Company’s mandatory convertible preferred stock.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

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

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

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

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 2016 presentation. The effects of the reclassifications were not material to the Company's consolidated financial statements. See Note 1 – New Accounting Standards Implemented in this Report for additional information regarding the reclassifications.

Principles of Consolidation

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

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

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

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

Cash and Cash Equivalents

Cash and cash equivalents are defined by the Company as short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash. Management considers cash and cash equivalents to have minimal credit and market risk as the Company monitors the credit status of the financial institutions holding its cash and marketable securities. The following table presents a summary of cash and cash equivalents as of December 31, 2016 and December 31, 2015:

	For the years ended December 31,	
	2016	2015
	(in millions)	
Cash	**$ 254**	$ 15
Marketable Securities [1]	**1,169**	–
Total	**$ 1,423**	$ 15

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

Certain of the Company's cash accounts are zero-balance controlled disbursement accounts. The Company presents the outstanding checks written against these zero-balance accounts as a component of accounts payable in the accompanying consolidated balance sheets. Outstanding checks included as a component of accounts payable totaled $8 million and $29 million as of December 31, 2016 and 2015, respectively.

Property, Depreciation, Depletion and Amortization

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

Costs associated with unevaluated properties are excluded from the amortization base until the properties are evaluated or impairment is indicated. The costs associated with unevaluated leasehold acreage and related seismic data, wells currently drilling and related capitalized interest are initially excluded from the amortization base. Leasehold costs are either transferred to the amortization base with the costs of drilling a well on the lease or are assessed at least annually for possible impairment or reduction in value. The Company's decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on several factors, including drilling plans, availability of capital, project economics and drilling results from adjacent acreage. At December 31, 2016, the Company had a total of $2,105 million of costs excluded from the amortization base, all of which related to its properties in the United States. Inclusion of some or all of these costs in the Company's United States properties in the future, without adding any associated reserves, could result in additional ceiling test impairments.

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

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 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. Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.59 per MMBtu, West Texas Intermediate oil of $46.79 per barrel and NGLs of $6.82 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by $1,586 million (net of tax) at December 31, 2015 and resulted in a non-cash ceiling test impairment. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2015.

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, for West Texas Intermediate oil of $91.48 per barrel and NGLs of $23.79 per barrel, adjusted for market differentials. The Company's net book value of its natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at December 31, 2014.

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

Capitalized Interest. Interest is capitalized on the cost of unevaluated natural gas and oil properties that are excluded from amortization and are 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 the wells are no longer producing. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred or when it becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

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

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

Income Taxes

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

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

Derivative Financial Instruments

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

Earnings Per Share

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

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

In January 2015, the Company completed concurrent underwritten public offerings of 30,000,000 shares of its common stock and 34,500,000 depositary shares (both share counts include shares issued as a result of the underwriters exercising their options to purchase additional shares). The common stock offering was priced at $23.00 per share. Net proceeds from the common stock offering were approximately $669 million, after underwriting discount and offering expenses. Net proceeds from the depositary share offering were approximately $1.7 billion, after underwriting discount and offering expenses. Each depositary share 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 (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 total potential shares of common stock resulting from the conversion will range from 63,829,830 to 74,999,895 shares.

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.

On December 12, 2016, the Company declared its quarterly dividend, payable to holders of the mandatory convertible preferred stock, and announced that it would pay the quarterly dividend in stock, in lieu of cash, to the extent permitted by the certificate of designations for the Series B preferred stock. The Company issued 2,751,410 shares of common stock on January 17, 2017 in payment for the dividend. Dividends declared in the first, second and third quarters of 2016 also were settled in common stock for a total of 7,166,389 shares, while the dividend declared in December 2015 was paid in cash in January 2016.

The following table presents the computation of earnings per share for the years ended December 31, 2016, 2015 and 2014:

	For the years ended December 31,		
	2016	2015	2014
	(in millions, except share/per share amounts)		
Net income (loss)	**$ (2,643)**	$ (4,556)	$ 924
Mandatory convertible preferred stock dividend	**108**	106	–
Net income (loss) attributable to common stock	**$ (2,751)**	$ (4,662)	$ 924
Number of common shares:			
Weighted average outstanding	**435,337,402**	380,521,039	351,446,747
Issued upon assumed exercise of outstanding stock options	**–**	–	241,603
Effect of issuance of non-vested restricted common stock	**–**	–	448,415
Effect of issuance of non-vested performance units	**–**	–	273,918
Effect of issuance of mandatory convertible preferred stock	**–**	–	–
Effect of declaration of preferred stock dividends	**–**	–	–
Weighted average and potential dilutive outstanding	**435,337,402**	380,521,039	352,410,683
Earnings (loss) per common share:			
Basic	**$ (6.32)**	$ (12.25)	$ 2.63
Diluted	**$ (6.32)**	$ (12.25)	$ 2.62

The following table presents the common stock shares equivalent excluded from the calculation of diluted earnings per share for the years ended December 31, 2016, 2015 and 2014, as they would have had an antidilutive effect:

	For the years ended December 31,		
	2016	2015	2014
Unvested stock options	**3,692,697**	3,835,234	1,446,004
Unvested share-based payment	**959,233**	1,990,383	29,879
Performance units	**884,644**	140,414	–
Mandatory convertible preferred stock	**74,999,895**	70,890,312	–
Declared and unpaid preferred stock dividends	**2,751,410**	–	–
Total	**83,287,879**	76,856,343	1,475,883

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, 2016, 2015, and 2014:

	For the years ended December 31,		
	2016	2015	2014
		(in millions)	
Cash paid during the year for interest, net of amounts capitalized	**$ 75**	$ 6	$ 50
Cash paid (received) during the year for income taxes	**(15)**	(6)	28
Increase (decrease) in noncash property additions	**55**	(10)	174

Stock-Based Compensation

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

Treasury Stock

The Company maintains a non-qualified deferred compensation supplemental retirement savings plan for certain key employees whereby participants may elect to defer and contribute a portion of their compensation to a Rabbi Trust, as permitted by the plan. The Company includes the assets and liabilities of its supplemental retirement savings plan in its consolidated balance sheet. Shares of the Company's common stock purchased under the non-qualified deferred compensation arrangement are held in the Rabbi Trust, are presented as treasury stock and are carried at cost. As of December 31, 2016, 31,269 shares were accounted for as treasury stock, compared to 47,149 shares at December 31, 2015.

Foreign Currency Translation

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

New Accounting Standards Implemented in this Report

In 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 adopted this update in the first quarter of 2016 resulting in no impact 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 adopted this update in the first quarter of 2016 resulting in no impact on its consolidated results of operations, financial position and cash flows. As a result of adoption, certain of the Company's pension plan assets measured using net asset value as a practical expedient have not been classified in the fair value hierarchy in Note 11 – Retirement and Employee Benefit Plans.

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Interest-Imputation of Interest (Subtopic 835-30) ("Update 2015-03"), in an effort to simplify presentation of debt issuance costs. Update 2015-03 required 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 was not affected by the amendments in this Update. Entities were required to apply the amendments in Update 2015-03 on a retrospective basis, with the balance sheet of each individual period presented 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 addressed 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 adopted this update in the first quarter of 2016 resulting in an immaterial impact on its consolidated financial position. The Company had $24 million in unamortized debt expense that was classified as a long-term asset at December 31, 2015, which is now presented as a contra-liability as a result of adoption.

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"), which addressed 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 was effective for annual reporting periods beginning after December 15, 2015 including interim periods within that reporting period. The Company adopted this update in the first quarter of 2016 resulting in no impact on its consolidated results of operations, financial position and cash flows.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern (Subtopic 205-40) ("Update 2014-15"), which requires management to assess a company's ability to continue as a going concern and to provide related footnote disclosures in certain circumstances. For public entities, Update 2014-15 was effective for annual reporting periods ending after December 15, 2016. The Company adopted this update in the first quarter of 2016 resulting in no impact on its consolidated results of operations, financial position, cash flows and disclosures.

New Accounting Standards Not Yet Implemented in this Report

In August 2016, the FASB issued Accounting Standards Update No. 2016-15, Statement of Cash Flows (Topic 230) ("Update 2016-15"), which seeks to reduce the existing diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. For public entities, Update 2016-15 becomes effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. The Company is currently evaluating the provisions of Update 2016-15 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Compensation – Stock Compensation (Topic 718) ("Update 2016-09"), which seeks to simplify accounting for share-based payment transactions including income tax consequences, classification of awards as either equity or liabilities, and the classification on the statement of cash flows. For public entities, Update 2016-09 becomes effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, with early adoption permitted. The Company expects to adopt this guidance effective January 1, 2017. The recognition of previously unrecognized windfall tax benefits is expected to result in a cumulative-effect adjustment of approximately $149 million, which would increase net deferred tax assets and increase the valuation allowance by the same amount as of the beginning of 2017. The remaining provisions of this amendment are not expected to have a material effect on the consolidated results of operations, financial position or cash flows.

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

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("Update 2014-09"), which seeks to provide clarity for recognizing revenue. The new standard removes inconsistencies in existing standards, changes the way companies recognize revenue from contracts with customers and increases disclosure requirements. The codification was amended through additional ASUs and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The standard is required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with a cumulative adjustment to retained earnings on the opening balance sheet. The Company has not yet selected a transition method. The Company has a team in place to analyze the impact of Update 2014-09, and the related ASU's, across all revenue streams to evaluate the impact of the new standard on revenue contracts. This includes reviewing current accounting policies and practices to identify potential differences that would result from applying the requirements under the new standard. In 2016, the Company made progress on contract reviews, drafting its accounting policies and evaluating the new disclosure requirements. The Company expects to complete its evaluations of the impacts of the accounting and disclosure requirements on its business processes, controls and systems in the second half of 2017. For public entities, the new standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period.

(2) REDUCTION IN WORKFORCE

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

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

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

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

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

The following table presents a summary of liabilities associated with the Company's restructuring activities for the year ended December 31, 2016, which are reflected in accounts payable on the unaudited condensed consolidated balance sheet:

		(in millions)
Liability at December 31, 2015	$	–
Additions		49
Distributions		(48)
Liability at December 31, 2016	$	1

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

(3) ACQUISITIONS AND DIVESTITURES

In September 2016, the Company sold approximately 55,000 net acres in West Virginia for approximately $422 million, which reflects customary adjustments at closing and is subject to customary post-closing adjustments. The Company accounted for the sale of these natural gas and oil properties as adjustments to capitalized costs, with no recognition of gain or loss as the sales did not involve a significant change in proved reserves or significantly alter the relationship between costs and proved reserves. In September 2016, $48 million of the net proceeds was used to repay borrowings under the Company's term loan entered into in November 2015. The Company intends to use the remaining net proceeds from the sale for general corporate purposes, including to fund capital projects.

In May 2015, the Company sold conventional oil and gas assets located in East Texas and the Arkoma Basin for approximately $211 million. The Company also accounted for the sale of these natural gas and oil properties as adjustments to capitalized costs, with no recognition of gain or loss as the sales did not involve a significant change in proved reserves or significantly alter the relationship between costs and proved reserves. 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 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 Services segment as of the closing date. A gain on sale of $283 million was recognized and was included in gain on sale of assets, net on the consolidated statement of operations. The assets included approximately 100 miles of natural gas gathering pipelines, with nearly 600 million cubic feet per day of capacity. The proceeds from the transaction were used to 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 transport is being amortized over 19 years. As of December 31, 2016 and 2015 the Company has amortized $17 million and $8 million, respectively. This transaction was funded with the revolving credit facility and was accounted for as a business combination. The following table summarizes the consideration paid for the WPX Property Acquisition and the fair value of the assets acquired and liabilities assumed as of the acquisition date:

		(in millions)
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 of certain natural gas and oil assets from Statoil ASA including approximately 30,000 net acres in West Virginia and southwest Pennsylvania for $357 million, which was comprised of approximately 20% of Statoil's interests in the properties, (the "Statoil Property Acquisition"). All of these assets were also assets in which the Company had acquired interests under the Chesapeake Property Acquisition as defined below. This transaction was funded with the revolving credit facility and was accounted for as a business combination. The Company allocated the purchase price to natural gas and oil properties, based on the respective fair values of the assets acquired.

In December 2014, the Company completed an acquisition of certain gas and oil assets from Chesapeake Energy Corporation covering approximately 413,000 net acres in West Virginia and southwest Pennsylvania targeting natural gas, oil and NGLs contained in the Upper Devonian, Marcellus and Utica Shales for approximately $5.0 billion (the "Chesapeake Property Acquisition"). The transaction 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 northeastern 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:

	(in millions)
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 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 considered 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.

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 year ended December 31, 2014 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
	(unaudited)	
Revenues (in millions)	$ 4,439	$ 3,713
Net Income attributable to common stock (in millions)	803	594
Earnings per share:		
Basic	$ 2.11	$ 1.56
Diluted	2.10	1.56

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 natural gas, oil and NGL reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as defined in Note 6 – Fair Value Measurements.

(4) DERIVATIVES AND RISK MANAGEMENT

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

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

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

The following table provides information about the Company's financial instruments that are sensitive to changes in commodity prices and that are used to protect the Company's exposure. None of the financial instruments below are designated for hedge accounting treatment. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates as of December 31, 2016:

	Volume (Bcf)	Weighted Average Price per MMBtu Swaps	Sold Puts	Purchased Puts	Sold Calls	Basis Differential	Fair value at December 31, 2016 (in millions)
Financial protection on production							
2017							
Fixed price swaps	322	$ 3.07	$ –	$ –	$ –	$ –	$ (175)
Two-way costless collars	103	–	–	2.94	3.38	–	(42)
Three-way costless collars	135	–	2.29	2.97	3.30	–	(59)
Basis swaps	132	–	–	–	–	(0.87)	19
Total	692						$ (257)
2018							
Fixed price swaps	18	$ 3.00	$ –	$ –	$ –	$ –	$ (2)
Two-way costless collars	14	–	–	3.00	3.46	–	(6)
Three-way costless collars	208	–	2.37	2.96	3.37	–	(20)
Basis swaps	16	–	–	–	–	(0.94)	(4)
Total	256						$ (32)
2019							
Three-way costless collars	62	$ –	$ 2.50	$ 2.92	$ 3.35	$ –	$ (2)
Total	62						$ (2)
Sold call options							
2017	86	$ –	$ –	$ –	$ 3.25	$ –	$ (46)
2018	63	–	–	–	3.50	–	(18)
2019	52	–	–	–	3.50	–	(11)
2020	32	–	–	–	3.75	–	(6)
Total	233						$ (81)

The balance sheet classification of the assets and liabilities related to derivative financial instruments (none of which are designated for hedge accounting treatment) are summarized below as of December 31, 2016 and 2015:

	Derivative Assets		
	Balance Sheet Classification	Fair Value	
		December 31, 2016	December 31, 2015
		(in millions)	
Derivatives not designated as hedging instruments:			
Two-way costless collars	Derivative assets	**$ 8**	$ –
Three-way costless collars	Derivative assets	**11**	–
Basis swaps	Derivative assets	**32**	3
Fixed price swaps	Other long-term assets	**1**	–
Two-way costless collars	Other long-term assets	**2**	–
Three-way costless collars	Other long-term assets	**100**	–
Basis swaps	Other long-term assets	**1**	–
Total derivative assets		**$ 155**	$ 3

	Derivative Liabilities		
	Balance Sheet Classification	Fair Value	
		December 31, 2016	December 31, 2015
		(in millions)	
Derivatives not designated as hedging instruments:			
Fixed price swaps	Derivative liabilities	**$ 175**	–
Two-way costless collars	Derivative liabilities	**49**	–
Three-way costless collars	Derivative liabilities	**70**	–
Basis swaps	Derivative liabilities	**13**	–
Sold call options	Derivative liabilities	**46**	–
Interest rate swaps	Derivative liabilities	**2**	3
Fixed price swaps	Other long-term liabilities	**3**	–
Two-way costless collars	Other long-term liabilities	**9**	–
Three-way costless collars	Other long-term liabilities	**122**	–
Basis swaps	Other long-term liabilities	**5**	–
Sold call options	Other long-term liabilities	**35**	–
Interest rate swaps	Other long-term liabilities	**1**	2
Total derivative liabilities		**$ 530**	$ 5

At December 31, 2016, the net fair value of the Company's financial instruments related to natural gas was a $372 million liability. The net fair value of the Company's interest rate swaps was a $3 million liability as of December 31, 2016.

Derivative Contracts Not Designated for Hedge Accounting

As of December 31, 2016, the Company had no positions designated for hedge accounting treatment. Gains and losses on derivatives that are not designated for hedge accounting treatment, or that do not meet hedge accounting requirements, are recorded as a component of gain (loss) on derivatives on the consolidated statements of operations. Accordingly, the gain (loss) on derivatives component of the statement of operations reflects the gains and losses on both settled and unsettled derivatives. The Company calculates gains and losses on settled derivatives as the summation of gains and losses on positions which have settled within the reporting period. Only the settled gains and losses are included in the Company's realized commodity price calculations.

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

The following tables summarize the before-tax effect of fixed price swaps, purchased put options, two-way costless collars, three-way costless collars, basis swaps, sold call options and interest rate swaps not designated for hedge accounting on the consolidated statements of operations for the years ended December 31, 2016 and 2015:

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Unsettled	Gain (Loss) on Derivatives, Unsettled Recognized in Earnings For the years ended December 31, 2016	2015
		(in millions)	
Fixed price swaps	Gain (Loss) on Derivatives	**$ (177)**	$ (164)
Two-way costless collars	Gain (Loss) on Derivatives	**(48)**	–
Three-way costless collars	Gain (Loss) on Derivatives	**(81)**	–
Basis swaps	Gain (Loss) on Derivatives	**12**	(2)
Sold call options	Gain (Loss) on Derivatives	**(81)**	13
Interest rate swaps	Gain (Loss) on Derivatives	**2**	(2)
Total loss on unsettled derivatives		**$ (373)**	$ (155)

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled	Gain (Loss) on Derivatives, Settled (1) Recognized in Earnings For the years ended December 31, 2016	2015
		(in millions)	
Fixed price swaps	Gain (Loss) on Derivatives	**$ –**	$ 208
Purchased put options	Gain (Loss) on Derivatives	**11**	–
Two-way costless collars	Gain (Loss) on Derivatives	**3**	–
Three-way costless collars	Gain (Loss) on Derivatives	**1**	–
Basis swaps	Gain (Loss) on Derivatives	**21**	(2)
Interest rate swaps	Gain (Loss) on Derivatives	**(2)**	(4)
Total gain on settled derivatives (2)		**$ 34**	$ 202
Total gain (loss) on derivatives		**$ (339)**	$ 47

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

(2) Excluding interest rate swaps, these amounts are included, along with gas sales revenues, in the calculation of the Company's realized natural gas price.

Derivative Contracts Designated for Hedge Accounting

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

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

The following tables detail the components of accumulated other comprehensive income (loss), net of related tax effects, for the year ended December 31, 2016:

	For the year ended December 31, 2016		
	Pension and Other Postretirement	Foreign Currency	**Total**
		(in millions)	
Beginning balance, December 31, 2015	$ (25)	$ (23)	**$ (48)**
Other comprehensive income (loss) before reclassifications	(7)	3	**(4)**
Amounts reclassified from other comprehensive income (loss) (1)	13	–	**13**
Net current-period other comprehensive income (loss)	6	3	**9**
Ending balance, December 31, 2016	**$ (19)**	**$ (20)**	**$ (39)**

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

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from Accumulated Other Comprehensive Income
		For the year ended December 31, 2016
		(in millions)
Pension and other postretirement:		
Amortization of prior service cost and net loss (1)	General and administrative expenses	$ 21
	Provision (benefit) for income taxes	8
	Net income (loss)	$ 13
Total reclassifications for the period	Net income (loss)	$ 13

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

(6) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2016 and 2015 were as follows:

	December 31, 2016		December 31, 2015	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(in millions)		
Cash and cash equivalents	**$ 1,423**	**$ 1,423**	$ 15	$ 15
Credit facility	**–**	**–**	116	116
Term loan facility due December 2020 (1)	**327**	**327**	750	750
Term loan facility due December 2020 (1)	**1,191**	**1,191**	–	–
Senior notes	**3,166**	**3,182**	3,867	2,672
Derivative instruments, net	**(375)**	**(375)**	(2)	(2)

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

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

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

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

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

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

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

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

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

The Company has classified its derivatives into these levels depending upon the data utilized to determine their fair values. The Company's fixed price swaps (Level 2) are estimated using third-party discounted cash flow calculations using the NYMEX futures index. The Company utilized discounted cash flow models for valuing its interest rate derivatives (Level 2). The net derivative values attributable to the Company's interest rate derivative contracts as of December 31, 2016 are based on (i) the contracted notional amounts, (ii) active market-quoted London Interbank Offered Rate ("LIBOR") yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's sold call options, purchased put options, two-way costless collars and three-way costless collars (Level 3) are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX futures index, interest rates, volatility and credit worthiness. The Company's basis swaps (Level 3) are estimated using third-party calculations based upon forward commodity price curves.

Inputs to the Black-Scholes model, including the volatility input, which is the significant unobservable input for Level 3 fair value measurements, are obtained from a third-party pricing source, with independent verification of the most significant inputs on a monthly basis. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively.

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

	December 31, 2016			
	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	**$ –**	**$ 1**	**$ –**	**$ 1**
Two-way costless collars assets	**–**	**–**	**10**	**10**
Three-way costless collars assets	**–**	**–**	**111**	**111**
Basis swap assets	**–**	**–**	**33**	**33**
Fixed price swap liabilities	**–**	**(178)**	**–**	**(178)**
Two-way costless collars liabilities	**–**	**–**	**(58)**	**(58)**
Three-way costless collars liabilities	**–**	**–**	**(192)**	**(192)**
Basis swap liabilities	**–**	**–**	**(18)**	**(18)**
Sold call option liabilities	**–**	**–**	**(81)**	**(81)**
Interest rate swap liabilities	**–**	**(3)**	**–**	**(3)**
Total	**$ –**	**$ (180)**	**$ (195)**	**$ (375)**

	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
Basis swap assets	$ –	$ –	$ 3	$ 3
Interest rate swap liabilities	–	(5)	–	(5)
Total	$ –	$ (5)	$ 3	$ (2)

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, 2016 and 2015. 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, 2016 and 2015.

	For the years ended December 31, 2016	2015
	(in millions)	
Balance at beginning of period	$ 3	$ (8)
Total gains (losses):		
Included in earnings	(162)	9
Settlements	(36)	2
Transfers into/out of Level 3	–	–
Balance at end of period	$ (195)	$ 3
Change in gains (losses) included in earnings relating to derivatives still held as of December 31	$ (198)	$ 11

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

(7) DEBT

The components of debt as of December 31, 2016 and 2015 consisted of the following:

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

(1) In July 2016, $375 million was repaid on the term loan facility, extending the maturity from November 2018 to December 2020, which will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due in January 2020. In September 2016, an additional $48 million was repaid.

(2) The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due in January 2020.

(3) In July 2016, the Company purchased approximately $312 million of the 3.30% Senior Notes due January 2018 and $388 million of the 7.50% Senior Notes due February 2018.

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

	December 31, 2015			
	Debt Instrument	Unamortized Issuance Cost	Unamortized Debt Discount	Total
	(in millions)			
Short-term debt:				
7.15% Senior Notes due June 2018	$ 1	$ –	$ –	$ 1
Total short-term debt	$ 1	$ –	$ –	$ 1
Long-term debt:				
Variable rate (1.886% at December 31, 2015) credit facility, expires December 2018	116	–	–	116
Variable rate (1.775% at December 31, 2015) term loan facility, due November 2018	750	(3)	–	747
7.35% Senior Notes due October 2017	15	–	–	15
7.125% Senior Notes due October 2017	25	–	–	25
3.30% Senior Notes due January 2018	350	(2)	–	348
7.50% Senior Notes due February 2018	600	(2)	–	598
7.15% Senior Notes due June 2018	26	–	–	26
4.05% Senior Notes due January 2020	850	(5)	(1)	844
4.10% Senior Notes due March 2022	1,000	(5)	(1)	994
4.95% Senior Notes due January 2025	1,000	(7)	(2)	991
Total long-term debt	$ 4,732	$ (24)	$ (4)	$ 4,704
Total debt	$ 4,733	$ (24)	$ (4)	$ 4,705

The following is a summary of scheduled debt maturities by year as of December 31, 2016 (in millions):

2017	$ 41
2018	275
2019	–
2020	2,368
2021	–
Thereafter	2,000
	$ 4,684

2016 Credit Facility

In June 2016, the Company reduced its existing $2.0 billion unsecured revolving credit facility to $66 million and entered into a new credit agreement for $1,934 million, consisting of a $1,191 million secured term loan and a new $743 million unsecured revolving credit facility, which matures in December 2020. The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due January 2020. The $1,191 million secured term loan is fully drawn, with approximately $285 million of this balance used to pay down the previous revolving credit facility balance in its entirety. As of December 31, 2016, there were no borrowings under either revolving credit facility; however, $174 million in letters of credit was outstanding against the 2016 revolving credit facility.

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

The new term loan and revolving credit facility contain financial covenants that impose certain restrictions on the Company. Under the new credit agreement, the Company must maintain a minimum interest coverage of 0.75x in 2016, increasing by 0.25x increments per year to 1.50x in 2019 and 2020. The Company is also subject to a minimum liquidity requirement of $300 million, which could be increased up to $500 million upon certain conditions, as well as an anti-hoarding provision, requiring unrestricted cash in excess of $100 million to pay down any amounts borrowed under the new revolving credit facility. The financial covenant with respect to minimum interest coverage consists of EBITDAX divided by consolidated interest expense. EBITDAX, as defined in our 2016 credit agreement, excludes the effects of interest expense, income taxes, depreciation, depletion and amortization, any non-cash impacts from impairments, certain non-cash hedging activities, stock-based compensation expense, non-cash gains or losses on asset sales, unamortized issuance cost, unamortized debt discount and certain restructuring costs. Collateral for the new secured term loan is principally the Company's E&P properties in the Fayetteville Shale area, the equity of its subsidiaries and cash and marketable securities on hand, and the new credit agreement requires a minimum collateral coverage ratio of 1.50x for the 2016 secured term loan. This collateral also may support all or a part of revolving credit extensions depending on restrictions in the Company's senior notes indentures.

As of December 31, 2016, the Company was in compliance with all of the covenants of this credit agreement. Although the Company does not anticipate any violations of the financial covenants, its ability to comply with these covenants is dependent upon the success of its exploration and development program and upon factors beyond the Company's control, such as the market prices for natural gas, oil and NGLs.

2013 Credit Facility

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

The existing unsecured 2013 revolving credit facility includes a financial covenant under which the Company may not have total debt in excess of 60% of its total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any full cost ceiling impairments, certain hedging activities and the Company's pension and other postretirement liabilities. At December 31, 2016, the Company's adjusted book capital was 34% debt and 66% equity.

2015 Term Facility

In November 2015, the Company entered into a $750 million unsecured three-year term loan credit agreement with various lenders that was utilized to repay borrowings under the revolving credit facility. The interest rate on the term loan facility is determined based upon the Company's public debt ratings from Moody's and S&P and was 250 basis points over LIBOR as of December 31, 2016. 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 June 2016, this term loan agreement was amended to extend the maturity date upon a repayment threshold. From the net proceeds of the July 2016 equity offering, the Company repaid $375 million of the $750 million unsecured term loan, which had the effect of extending the term loan maturity from November 2018 to December 2020, which will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least $765 million of its senior notes due in January 2020. As a result of the repayment, the Company expensed $3 million of unamortized debt issuance costs, recognized in other interest charges on the consolidated statement of operations for the year ended December 31, 2016. In September 2016, the Company repaid an additional $48 million from the proceeds received from the closing of the sale of approximately 55,000 net acres in West Virginia to Antero Resources Corporation, resulting in an additional $0.4 million of interest expense related to unamortized debt issuance costs.

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, 2016 and 2015, the Company had no outstanding issuances under its commercial paper program, respectively, and had no current plans of further utilizing the commercial paper market.

Senior Notes

In July 2016, the Company used a portion of the proceeds from the July 2016 equity offering to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of the Company's outstanding senior notes due in the first quarter of 2018, resulting in a loss of $51 million for the early retirement and redemption of these senior notes including $50 million of premiums paid. Additionally, the Company expensed $2 million of unamortized debt issuance costs and debt discounts, recognized in other interest charges.

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, 2016. 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 are determined based upon the public bond ratings from Moody’s and S&P. Downgrades on the Notes from either rating agency increase interest costs by 25 basis points per downgrade level and upgrades decrease interest costs by 25 basis points per upgrade level, up to the stated coupon rate, on the following semi-annual bond interest payment. In February and June 2016, Moody’s and S&P downgraded the Notes, increasing the interest rates by 175 basis points effective July 2016. As a result of these downgrades, interest rates increased to 5.05% for the 2018 Notes, 5.80% for the 2020 Notes and 6.70% for the 2025 Notes. In the event of future downgrades, the coupons for this series of notes are capped at 5.30%, 6.05% and 6.95%, respectively. The first coupon payment to the bondholders at the higher interest rates was paid in January 2017.

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 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. 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.

(8) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of December 31, 2016, the Company’s contractual obligations for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems totaled approximately $8.4 billion, $3.4 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. The Company also had guarantee obligations of up to $862 million of that amount. As of December 31, 2016, future payments under non-cancelable firm transportation and gathering agreements are as follows:

	Payments Due by Period					
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 years	More than 8 Years
			(in millions)			
Infrastructure Currently in Service	**$ 5,067**	$ 612	$ 1,158	$ 825	$ 829	$ 1,643
Pending Regulatory Approval and/or Construction (1)	**3,362**	15	326	450	678	1,893
Total Transportation Charges	**$ 8,429**	$ 627	$ 1,484	$ 1,275	$ 1,507	$ 3,536

(1) Based on the estimated in-service dates as of December 31, 2016.

The Company has 13 leases for pressure pumping equipment for its E&P operations under leases that expire between December 2017 and January 2018. The Company’s current aggregate annual payment under the leases is approximately $8 million. Certain of these leases provide for a residual value guarantee for any deficiency if the equipment is sold for less than the sale option amount (recognized as a liability of approximately $4 million at December 31, 2016). The Company has 7 leases for drilling rigs for its E&P operations that expire through 2021 with a current aggregate annual payment of approximately $13 million. The lease payments for the pressure pumping equipment, as well as other operating expenses for the Company’s drilling operations, are capitalized to natural gas and oil properties and are partially offset by billings to third-party working interest owners 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, 2016, future minimum payments under these non-cancelable leases accounted for as operating leases are approximately $66 million in 2017, $52 million in 2018, $45 million in 2019, $35 million in 2020, $17 million in 2021 and $14 million thereafter.

The Company also has commitments for compression services related to its Midstream Services and E&P segments. As of December 31, 2016, future minimum payments under these non-cancelable agreements are approximately $16 million in 2017, $7 million in 2018 and $3 million in 2019.

Environmental Risk

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

Litigation

The Company is subject to various litigation, claims and proceedings that have arisen in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties, 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.

Berry-Helfand (Tovah Energy)

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., then pending in the 273rd District Court in Shelby County, Texas. The plaintiff alleged that the subsidiary used information provided by the plaintiff under a confidentiality agreement, which she claimed, among other things, breached the agreement and constituted a trade secret. Following a trial in December 2010, the court awarded approximately $11 million in actual damages and approximately $24 million in disgorgement of profits, along with interest and attorneys' fees. Both sides appealed, and in July 2013 the Texas Court of Appeals for the Twelfth District reversed on all claims except misappropriation of trade secrets, reduced the judgment to the actual damages award, along with interest and attorneys' fees, and ordered the case remanded for an award of attorneys' fees to the Company's subsidiary on one of the claims on which judgment was reversed. Both parties petitioned the Supreme Court of Texas for review. In June 2016, the Supreme Court ruled that insufficient evidence supported the damage award and remanded the case for a new trial. The parties subsequently reached a settlement, the amount of which is reflected in the Company's financial statements as of, and for the period ended, December 31, 2016.

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.

In November 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. In April 2016, the court certified a broader class that includes Arkansas residents and citizens. Class members were notified of the pending action in late 2016, and the period to "opt out" of the class has expired. 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 and production 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 the Company 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 class representative's disclosure regarding the calculation of claimed damages, class-wide damages could exceed $100 million. The court has set a trial date in the second quarter of 2017. The Company has moved for summary judgment on all claims, which remains pending before the trial judge.

The Company's subsidiaries appealed the class certification orders in the state cases. In December 2016 the Arkansas Supreme Court affirmed the certifications. These cases are now before the Arkansas trial judges. The precise configuration of the classes has not been determined, particularly in light of the overlapping composition of the class in the federal case. No date for trial has been set.

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.

(9) INCOME TAXES

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

	2016	2015	2014
		(in millions)	
Current:			
Federal	**$ (6)**	$ 1	$ 11
State	**(1)**	(3)	10
	(7)	(2)	21
Deferred:			
Federal	**(22)**	(1,697)	501
State	**–**	(304)	2
Foreign	**–**	(2)	1
	(22)	(2,003)	504
Provision (benefit) for income taxes	**$ (29)**	$ (2,005)	$ 525

The provision for income taxes was an effective rate of 1% in 2016, 31% in 2015 and 36% in 2014. 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:

	2016	2015	2014
		(in millions)	
Expected provision (benefit) at federal statutory rate	**$ (935)**	$ (2,296)	$ 507
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	**(79)**	(194)	58
Nondeductible expenses	**–**	–	3
State rate redetermination	**–**	–	(48)
Change in uncertain tax positions	**(19)**	(7)	–
Change in valuation allowance	**1,002**	495	5
Other	**2**	(3)	–
Provision (benefit) for income taxes	**$ (29)**	$ (2,005)	$ 525

Our effective tax rate decreased in 2016, as compared with 2015, primarily due to the recognition of a valuation allowance in the fourth quarter of 2015 that persisted throughout 2016.

The components of the Company's deferred tax balances as of December 31, 2016 and 2015 were as follows:

	2016	2015
	(in millions)	
Deferred tax liabilities:		
Differences between book and tax basis of property	$ 81	$ 216
Other	1	2
	82	218
Deferred tax assets:		
Accrued compensation	38	19
Alternative minimum tax credit carryforward	100	125
Accrued pension costs	19	19
Asset retirement obligations	53	77
Net operating loss carryforward	1,177	445
Derivative activity	142	–
Other	29	26
	1,558	711
Valuation allowance	(1,476)	(493)
Net deferred tax liability	$ –	$ –

In 2016, the Company paid less than $1 million in state income taxes and received $15 million in federal income tax refunds. In 2015, the Company paid less than $1 million in state income taxes and did not pay federal income taxes. The Company's net operating loss carryforward as of December 31, 2016 was $3.2 billion and $2.2 billion for federal and state reporting purposes, respectively, the majority of which will expire between 2029 and 2036. Additionally, the Company has an income tax net operating loss carryforward related to its Canadian operations of $35 million, with expiration dates of 2030 through 2036. The Company also had an alternative minimum tax credit carryforward of $100 million and a statutory depletion carryforward of $13 million as of December 31, 2016.

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

Due to the continued write-downs of the carrying value of natural gas and oil properties, the Company maintained its net deferred tax asset position at December 31, 2016. The Company believes it is more likely than not that these deferred tax assets will not be realized and recorded a $983 million increase in valuation allowance for the year ended December 31, 2016, 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. In management's view, the cumulative loss incurred over the three-year period ending December 31, 2016, outweighs any positive factors, such as the possibility of future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as future expected growth.

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 2016 due to net operating loss carryforwards, these "windfall" tax benefits are not reflected in its net operating losses in deferred tax assets for 2016. Windfalls included in net operating loss carryforwards but not reflected in deferred tax assets for 2016 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, 2016, the amount of unrecognized tax benefits related to alternative minimum tax was $17 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, 2016, the Company had accrued a liability of less than $1 million of interest related to this uncertain tax position. The Company recognizes penalties and interest related to uncertain tax positions in income tax expense.

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

	2016	2015
	(in millions)	
Unrecognized tax benefits at beginning of period	$ 37	$ 44
Additions based on tax positions related to the current year	–	7
Additions to tax positions of prior years	–	–
Reductions to tax positions of prior years	(20)	(14)
Unrecognized tax benefits at end of period	$ 17	$ 37

The Internal Revenue Service is currently auditing the Company's federal income tax return for 2014. The income tax years 2013 to 2016 remain open to examination by the major taxing jurisdictions to which the Company is subject.

(10) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the Company's 2016 and 2015 activity related to asset retirement obligations:

	2016	2015
	(in millions)	
Asset retirement obligation at January 1	$ 201	$ 207
Accretion of discount	10	11
Obligations incurred	1	17
Obligations settled/removed (1)	(45)	(30)
Revisions of estimates (2)	(26)	(4)
Asset retirement obligation at December 31	$ 141	$ 201
Current liability	6	10
Long-term liability	135	191
Asset retirement obligation at December 31	$ 141	$ 201

(1) Obligations settled/removed include $35 million and $25 million related to asset divestitures in 2016 and 2015, respectively.

(2) Estimates in the costs to retire wells and well pads were revised downward based on internal estimates of future obligation requirements and updated third-party cost quotes.

(11) RETIREMENT AND EMPLOYEE BENEFIT PLANS

401(k) Defined Contribution Plan

The Company has a 401(k) defined contribution plan covering eligible employees. The Company expensed $4 million, $3 million and $3 million of contribution expense in 2016, 2015 and 2014, respectively. Additionally, the Company capitalized $2 million, $4 million and $3 million of contributions in 2016, 2015 and 2014, respectively, directly related to the acquisition, exploration and development activities of the Company's natural gas and oil properties or directly related to the construction of the Company's gathering systems.

Defined Benefit Pension and Other Postretirement Plans

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

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

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

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

The following provides a reconciliation of the changes in the plans' benefit obligations, fair value of assets and funded status as of December 31, 2016 and 2015:

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	**2016**	2015
	(in millions)			
Change in benefit obligations:				
Benefit obligation at January 1	**$ 138**	$ 134	**$ 20**	$ 18
Service cost	**11**	16	**2**	3
Interest cost	**5**	6	**1**	1
Participant contributions	**–**	–	**–**	–
Actuarial loss (gain)	**14**	(7)	**(2)**	(2)
Benefits paid	**(3)**	(11)	**(1)**	–
Plan amendments	**–**	–	**–**	–
Curtailments	**(8)**	–	**(7)**	–
Settlements	**(40)**	–	**–**	–
Benefit obligation at December 31	**$ 117**	$ 138	**$ 13**	$ 20

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	**2016**	2015
	(in millions)			
Change in plan assets:				
Fair value of plan assets at January 1	**$ 108**	$ 108	**$ –**	$ –
Actual return on plan assets	**3**	(1)	**–**	–
Employer contributions	**10**	12	**1**	–
Participant contributions	**–**	–	**–**	–
Benefits paid	**(3)**	(11)	**(1)**	–
Settlements	**(37)**	–	**–**	–
Fair value of plan assets at December 31	**$ 81**	$ 108	**$ –**	$ –
Funded status of plans at December 31	**$ (36)**	$ (30)	**$ (13)**	$ (20)

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 gain of $7 million ($4 million after tax) for the year ended December 31, 2016 and a loss of $2 million ($2 million after tax) for the year ended December 31, 2015. The change in accumulated other comprehensive income related to the other postretirement benefit plan was a gain of $3 million ($2 million after tax) for the year ended December 31, 2016 and a gain of $1 million ($1 million after tax) for the year ended December 31, 2015. Included in accumulated other comprehensive income as of December 31, 2016 and 2015 was a $31 million loss ($19 million net of tax) and a $42 million loss ($25 million net of tax), respectively, related to the Company's pension and other postretirement benefit plans. For the year ended December 31, 2016, $6 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 2017 is a $1 million net loss.

The pension plans' projected benefit obligation, accumulated benefit obligation and fair value of plan assets as of December 31, 2016 and 2015 are as follows:

	2016	2015
	(in millions)	
Projected benefit obligation	$ 117	$ 138
Accumulated benefit obligation	116	135
Fair value of plan assets	81	108

Pension and other postretirement benefit costs include the following components for 2016, 2015 and 2014:

	Pension Benefits			Other Postretirement Benefits		
	2016	2015	2014	2016	2015	2014
	(in millions)					
Service cost	$ 11	$ 16	$ 13	$ 2	$ 3	$ 2
Interest cost	5	6	5	1	1	1
Expected return on plan assets	(6)	(9)	(7)	–	–	–
Amortization of transition obligation	–	–	–	–	–	–
Amortization of prior service cost	–	–	–	–	–	–
Amortization of net loss	2	2	1	–	–	–
Net periodic benefit cost	12	15	12	3	4	3
Curtailment loss	1	–	–	(6)	–	–
Settlement loss	11	–	–	–	–	–
Total benefit cost (benefit)	$ 24	$ 15	$ 12	$ (3)	$ 4	$ 3

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

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

The assumptions used in the measurement of the Company's benefit obligations as of December 31, 2016 and 2015 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	2016	2015
Discount rate	4.20 %	4.60 %	4.20 %	4.60 %
Rate of compensation increase	3.50 %	3.50 %	n/a	n/a %

The assumptions used in the measurement of the Company's net periodic benefit cost for 2016, 2015 and 2014 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2016	2015	2014	2016	2015	2014
Discount rate	4.20 %	4.25 %	5.00 %	4.20 %	4.25 %	5.00 %
Expected return on plan assets	7.00 %	7.00 %	7.00 %	n/a	n/a	n/a
Rate of compensation increase	3.50 %	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 2016 and 2015:

	2016	2015
Health care cost trend assumed for next year	**7%**	8%
Rate to which the cost trend is assumed to decline	**5%**	5%
Year that the rate reaches the ultimate trend rate	**2034**	2034

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

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

Pension Payments and Asset Management

In 2016, the Company contributed $10 million to its pension plans and $1 million to its other postretirement benefit plan. The Company expects to contribute $15 million to its pension and other postretirement benefit plans in 2017.

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

Pension Benefits		Other Postretirement Benefits	
	(in millions)		
2017	$ 8	2017	$ 1
2018	6	2018	1
2019	6	2019	1
2020	7	2020	1
2021	8	2021	1
Years 2022-2026	46	Years 2022-2026	6

The Company's overall investment strategy is to provide an adequate pool of assets to support both the long-term growth of plan assets and to ensure adequate liquidity exists for the near-term payment of benefit obligations to participants, retirees and beneficiaries. The Benefits Administration Committee of the Company 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, 2016, by asset category. The asset allocation targets are subject to change and the Benefits Administration Committee allows for its actual allocations to deviate from target as a result of current and anticipated market conditions. Plan assets are periodically balanced whenever the allocation to any asset class falls outside of the specified range.

	Pension Plan Asset Allocations	
Asset category:	Target	Actual
Equity securities:		
U.S. Equity (1)	35 %	36 %
Non-U.S. Developed Equity (2)	30 %	28 %
Emerging Markets Equity (3)	5 %	6 %
Opportunistic (4)	– %	– %
Fixed income (5)	28 %	25 %
Cash (6)	2 %	5 %
Total	100 %	100 %

(1) Includes the following equity securities in the table below: U.S. large cap growth equity, U.S. large cap value equity, U.S. large cap core equity, and U.S. small cap equity.
(2) Includes Non-U.S. equity securities in the table below.
(3) Includes emerging markets equity securities below.
(4) Includes none of the securities in the table below.
(5) Includes fixed income pension plan assets in the table below.
(6) Includes Cash and cash equivalents pension plan assets in the table below.

Utilizing the fair value hierarchy described in Note 6 – Fair Value Measurements, the Company's fair value measurement of pension plan assets as of December 31, 2016 is as follows:

	Total	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		(in millions)		
Measured within fair value hierarchy				
Equity securities:				
U.S. large cap growth equity (1)	$ 6	$ 6	$ –	$ –
U.S. large cap value equity (2)	6	6	–	–
U.S. small cap equity (3)	3	3	–	–
Non-U.S. equity (4)	23	23	–	–
Emerging markets equity (5)	4	4	–	–
Fixed income (6)	21	21	–	–
Cash and cash equivalents	4	4	–	–
Total measured within fair value hierarchy	$ 67	$ 67	$ –	$ –
Measured at net asset value (7)				
Equity securities:				
U.S. large cap core equity (8)	14			
Total measured at net asset value	$ 14			
Total plan assets at fair value	$ 81			

(1) Mutual fund that seeks to invest in a diversified portfolio of stocks with price appreciation growth opportunities.
(2) Mutual fund that seeks to invest in a diversified portfolio of stocks that will increase in value over the long-term as well as provide current income.
(3) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
(4) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.
(5) An institutional fund that invests primarily in the equity securities of companies domiciled in emerging markets.
(6) Institutional funds that seek an investment return that approximates, as closely as practicable, before expenses, the performance of the Barclays U.S. Intermediate Credit Bond Index over the long term and the Barclays Long U.S. Corporate Bond Index over the long-term.
(7) Plan assets for which fair value was measured using net asset value as a practical expedient.
(8) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.

Utilizing the fair value hierarchy described in Note 6 – Fair Value Measurements, the Company's fair value measurement of pension plan assets at December 31, 2015 is as follows:

	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(in millions)		
Measured within fair value hierarchy				
Equity securities:				
U.S. large cap growth equity (1)	$ 9	$ 9	$ –	$ –
U.S. large cap value equity (2)	9	9	–	–
U.S. small cap equity (3)	3	3	–	–
Non-U.S. equity (4)	31	31	–	–
Emerging markets equity (5)	5	5	–	–
Cash and cash equivalents	2	2	–	–
Total measured within fair value hierarchy	$ 59	$ 59	$ –	$ –
Measured at net asset value (6)				
Equity securities:				
U.S. large cap core equity (7)	18			
Fixed income (8)	31			
Total measured at net asset value	$ 49			
Total plan assets at fair value	$ 108			

(1) Mutual fund that seeks to invest in a diversified portfolio of stocks with price appreciation growth opportunities.
(2) Mutual fund that seeks to invest in a diversified portfolio of stocks that will increase in value over the long-term as well as provide current income.
(3) Mutual fund that seeks to invest in a diversified portfolio of stocks with small market capitalizations.
(4) Mutual funds that invest primarily in equity securities of companies domiciled outside of the United States, primarily in developed markets.
(5) An institutional fund that invests primarily in the equity securities of companies domiciled in emerging markets.
(6) Plan assets for which fair value was measured using net asset value as a practical expedient.
(7) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.
(8) 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 the investments comprised of either cash or investments in open-ended mutual funds which produce a daily net asset value that is validated with a sufficient level of observable activity to support classification of the fair value measurement as Level 1. Due to the Company's implementation of Accounting Standards Update No. 2015-07, assets measured using net asset value as a practical expedient have not been classified in the fair value hierarchy. No concentration of risk arising within or across categories of plan assets exists due to any significant investments in a single entity, industry, country or investment fund.

(12) STOCK-BASED COMPENSATION

The Southwestern Energy Company 2013 Incentive Plan was adopted in February 2013, approved by stockholders in May 2013 and amended and restated per stockholders' approval in May 2016 (the "2013 Plan"). The 2013 Plan provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2013 Plan 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 33,850,000 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).

In January 2016, the Company announced a 40% workforce reduction that was substantially concluded by the end of March 2016. In April 2016, the Company also partially restructured executive management, which was substantially completed in the second quarter of 2016. Affected employees were offered a severance package that included, if applicable, amendments to certain outstanding equity awards that modified forfeiture provisions upon separation from the Company. As a result, certain unvested stock-based equity awards became fully vested at the time of separation. These shares were revalued and recognized immediately as a component of restructuring charges on the Company's unaudited consolidated statement of operations. The unvested portion of equity-based performance units was forfeited upon separation from the Company.

Stock Options

The Company recorded the following compensation costs related to stock options for the years ended December 31, 2016, 2015 and 2014:

	2016	2015	2014
		(in millions)	
Stock-based compensation cost related to stock options – general and administrative expense (1)	**$ 6**	$ 5	$ 5
Stock-based compensation cost related to stock options – capitalized	**$ 1**	$ 3	$ 4

(1) Includes less than $1 million and $1 million related to the reduction in workforce and executive management restructuring, respectively, for the year ended December 31, 2016.

The Company also recorded a deferred tax asset of $2 million, $2 million and $3 million related to stock options in 2016, 2015 and 2014, respectively. Unrecognized compensation cost related to the Company's unvested stock options totaled $4 million at December 31, 2016. This cost is expected to be recognized over a weighted-average period of 2 years.

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's common stock and other factors. The Company uses historical data on the exercise of stock options, post-vesting forfeitures and other factors to estimate the expected term of the stock-based payments granted. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant.

Assumptions	**2016**	2015	2014
Risk-free interest rate	**1.4%**	1.7%	1.6%
Expected dividend yield	**–**	–	–
Expected volatility	**41.0%**	36.0%	32.5%
Expected term	**5 years**	5 years	5 years

The following tables summarize stock option activity for the years 2016, 2015 and 2014, and provide information for options outstanding at December 31 of each year:

	2016		2015		2014	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Options outstanding at January 1	**5,623**	**$ 24.57**	3,622	$ 35.41	3,313	$ 35.70
Granted [1]	**155**	**8.60**	2,401	9.47	835	32.31
Exercised	**(45)**	**7.74**	–	–	(402)	30.60
Forfeited or expired	**(317)**	**38.01**	(400)	32.20	(124)	37.80
Options outstanding at December 31	**5,416**	**$ 23.46**	5,623	$ 24.57	3,622	$ 35.41

(1) Shares granted in 2016 are considerably lower than historical norms. In 2016, the Company changed the grant date of its annual stock option awards from December to the following February.

	Options Outstanding				Options Exercisable			
Range of Exercise Prices	Options Outstanding at December 31, 2016	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value	Options Exercisable at December 31, 2016	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
	(in thousands)		(years)	(in millions)	(in thousands)		(years)	(in millions)
$7.74-$29.69	2,501	9.54	5.9		781	9.77	5.8	
$30.59-$35.91	1,384	32.32	3.9		1,146	32.68	3.7	
$36.22-$39.68	1,402	37.49	2.4		1,402	37.49	2.4	
$40.15-$51.47	129	45.79	3.3		99	45.57	3.0	
	5,416	$ 23.46	4.4	$ 7	3,428	$ 29.80	3.6	$ 2

The weighted-average grant date fair value of options granted during the years 2016, 2015 and 2014 was $3.22, $3.16 and $10.16, respectively. The total intrinsic value of options exercised during 2016 and 2014 was less than $1 million and $4 million, respectively. There were no options exercised in 2015.

Restricted Stock

The Company recorded the following compensation costs related to restricted stock grants for the years ended December 31, 2016, 2015 and 2014:

	2016	2015	2014
		(in millions)	
Stock-based compensation cost related to restricted stock grants – general and administrative expense [1]	**$ 33**	$ 14	$ 10
Stock-based compensation cost related to restricted stock grants – capitalized	**$ 8**	$ 16	$ 12

(1) Includes $16 million and $1 million related to the reduction in workforce and executive management restructuring, respectively, for the year ended December 31, 2016.

The Company also recorded a deferred tax asset of $12 million related to restricted stock for the year ended December 31, 2016, compared to a deferred tax asset of $11 million for 2015 and a deferred tax liability of $10 million for 2014. As of December 31, 2016, there was $37 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 2 years.

The following table summarizes the restricted stock activity for the years 2016, 2015 and 2014, and provides information for restricted stock outstanding at December 31 of each year:

	2016			2015			2014		
	Number of Shares		**Weighted Average Fair Value**	Number of Shares		Weighted Average Fair Value	Number of Shares		Weighted Average Fair Value
	(in thousands)			(in thousands)			(in thousands)		
Unvested shares at January 1	**7,222**	**$**	**13.24**	2,376	$	34.00	1,771	$	37.55
Granted (1)	**81**		**8.56**	5,822		8.07	1,295		30.89
Vested (2)	**(3,817)**		**11.34**	(873)		33.33	(548)		37.12
Forfeited	**(165)**		**12.05**	(103)		29.14	(142)		37.91
Unvested shares at December 31	**3,321**	**$**	**11.85**	7,222	$	13.24	2,376	$	34.00

(1) Shares granted in 2016 are considerably lower than historical norms. In 2016, the Company changed the grant date of its annual restricted stock awards from December to the following February.

(2) Includes 2,059,626 shares and 151,575 shares related to reduction in workforce and executive management restructuring, respectively, for the year ended December 31, 2016.

The fair values of the grants were $1 million for 2016, $47 million for 2015 and $40 million for 2014. The total fair value of shares vested were $43 million for 2016, $29 million for 2015 and $20 million for 2014.

Equity-Classified Performance Units

The Company recorded compensation costs related to equity-classified performance units for the years ended December 31, 2016, 2015 and 2014. The performance units awarded in 2013 and 2014 included 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 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 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 performance units awarded in 2016 and 2015 are based exclusively on TSR. The grant date fair value is calculated using the applicable Performance Measures and the closing price of the Company’s common stock at the grant date.

	2016		2015		2014	
			(in millions)			
Stock-based compensation cost related to performance units – general and administrative expense (1)	**$**	**9**	$	6	$	3
Stock-based compensation cost related to performance units – capitalized	**$**	**1**	$	4	$	2

(1) Includes less than $1 million and $1 million related to reduction in workforce and executive management restructuring, respectively, for the year ended December 31, 2016.

The Company also recorded a deferred tax asset of $4 million related to equity-based performance units for the year ended December 31, 2016, compared to deferred tax assets of $4 million and $2 million in 2015 and 2014, respectively. As of December 31, 2016, there was $9 million of total unrecognized compensation cost related to unvested equity-based performance units that is expected to be recognized over a weighted-average period of 2 years.

The following table summarizes performance unit activity to be paid out in Company stock for the years ended December 31, 2016, 2015 and 2014, and provides information for unvested units as of December 31, 2016, 2015 and 2014:

	2016		2015		2014	
	Number of Units (1)	**Weighted Average Fair Value**	Number of Units (1)	Weighted Average Fair Value	Number of Units (1)	Weighted Average Fair Value
	(in thousands)		(in thousands)		(in thousands)	
Unvested shares at January 1	**407**	**$ 36.65**	223	$ 40.44	–	$ –
Granted	**1,503**	**8.60**	443	35.22	359	40.44
Vested (2)	**(889)**	**12.78**	(259)	37.46	(111)	40.44
Forfeited (3)	**(302)**	**11.26**	–	–	(25)	40.44
Unvested shares at December 31	**719**	**$ 11.46**	407	$ 36.65	223	$ 40.44

(1) These amounts reflect the number of performance units granted in thousands. The actual payout in shares may range from a minimum of zero shares to a maximum of two shares contingent upon the actual performance against the Performance Measures. The performance units have a three-year vesting term and the actual disbursement of shares, if any, is not determined until March following the end of the three-year vesting period.

(2) Includes 22,918 units and 37,590 units related to the reduction in workforce and executive management restructuring, respectively, for the year ended December 31, 2016.

(3) Includes 87,595 units and 195,834 units related to the reduction in workforce and executive management restructuring, respectively, for the year ended December 31, 2016.

Liability-Classified Performance Units

Prior to 2013, certain employees were provided performance units vesting equally over three years that were settled in cash. The payout of these units was based on certain metrics, such as total shareholder return and reserve replacement efficiency, compared to a predetermined group of peer companies and Company goals. At the end of each performance period, the value of the vested performance units, if any, would be paid in cash. In the first quarter of 2016, the Company completed the final payout under these performance unit agreements.

(13) SEGMENT INFORMATION

The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and liquids. The Midstream 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, loss on early extinguishment of debt and other income (loss). The "Other" column includes items not related to the Company's reportable segments, including real estate and corporate items.

	Exploration and Production	Midstream Services	Other	**Total**
		(in millions)		
2016				
Revenues from external customers	**$ 1,435**	**$ 1,001**	**$ –**	**$ 2,436**
Intersegment revenues	**(22)**	**1,568**	**–**	**1,546**
Depreciation, depletion and amortization expense	**371**	**65**	**–**	**436**
Impairment of natural gas and oil properties	**2,321**	**–**	**–**	**2,321**
Operating income (loss)	**(2,404)** (1)	**209** (2)	**–**	**(2,195)**
Interest expense (3)	**87**	**1**	**–**	**88**
Gain (loss) on derivatives	**(338)**	**(1)**	**–**	**(339)**
Loss on early extinguishment of debt	**–**	**–**	**(51)**	**(51)**
Other income (loss), net	**5**	**(2)**	**(2)**	**1**
Provision (benefit) for income taxes (3)	**(29)**	**–**	**–**	**(29)**
Assets	**4,178** (4)	**1,331**	**1,567** (5)	**7,076**
Capital investments (6)	**623**	**21**	**4**	**648**
2015				
Revenues from external customers	$ 2,095	$ 1,038	$ –	**$ 3,133**
Intersegment revenues	(21)	2,081	–	**2,060**
Depreciation, depletion and amortization expense	1,028	62	1	**1,091**
Impairment of natural gas and oil properties	6,950	–	–	**6,950**
Operating income (loss)	(7,104)	583 (7)	(1)	**(6,522)**
Interest expense (3)	47	9	–	**56**
Gain (loss) on derivatives	51	–	(4)	**47**
Other loss, net	(21)	(9)	–	**(30)**
Provision (benefit) for income taxes (3)	(2,273)	268	–	**(2,005)**
Assets	6,588 (4)	1,290	208	**8,086**
Capital investments (6)	2,258	167	12	**2,437**
2014				
Revenues from external customers	$ 2,850	$ 1,188	$ –	**$ 4,038**
Intersegment revenues	12	3,170	–	**3,182**
Depreciation, depletion and amortization expense	884	58	–	**942**
Operating income (loss)	1,013	361	(1)	**1,373**
Interest expense (3)	47	12	–	**59**
Gain (loss) on derivatives	142	(1)	(2)	**139**
Other loss, net	(3)	(1)	–	**(4)**
Provision for income taxes (3)	402	123	–	**525**
Assets	13,018 (4)	1,554	343	**14,915**
Capital investments (6)	7,254	144	49	**7,447**

(1) Operating loss for the E&P segment includes $86 million related to restructuring and other one-time charges for the year ended December 31, 2016.

(2) Operating income for the Midstream Services segment includes $3 million related to restructuring charges for the year ended December 31, 2016.

(3) 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.

(4) Includes office, technology, drilling rigs and other ancillary equipment not directly related to natural gas and oil property acquisition, exploration and development activities.

(5) Other assets represent corporate assets not allocated to segments and assets for non-reportable segments. At December 31, 2016, other assets includes approximately $1.4 billion in cash and cash equivalents.

(6) Capital investments include an increase of $43 million for 2016, a decrease of $33 million for 2015 and an increase of $155 million for 2014 related to the change in accrued expenditures between years.

(7) Operating income (loss) for the Midstream Services segment includes a $277 million gain on sale of assets for the year ended December 31, 2015.

Included in intersegment revenues of the Midstream Services segment are $1.3 billion, $1.8 billion and $2.8 billion for 2016, 2015 and 2014, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments.

(14) SUBSEQUENT EVENTS

None.

SUPPLEMENTAL QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2016 and 2015:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(in millions, except per share amounts)			
	2016			
Operating revenues	**$ 579**	**$ 522**	**$ 651**	**$ 684**
Operating income (loss) [(1)]	**(1,100)**	**(492)**	**(725)**	**122**
Net loss attributable to common stock	**(1,159)**	**(620)**	**(735)**	**(237)**
Loss per share - Basic	**(3.03)**	**(1.61)**	**(1.52)**	**(0.48)**
Loss per share - Diluted	**(3.03)**	**(1.61)**	**(1.52)**	**(0.48)**
	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 (Loss) per share - Basic	0.12	(2.13)	(4.62)	(5.58)
Earnings (Loss) per share - Diluted	0.12	(2.13)	(4.62)	(5.58)

(1) The operating losses for the first, second and third quarters of 2016 included non-cash full cost impairments of natural gas and oil properties of $1,034 million, $470 million, and $817 million, respectively. There was no full cost impairment in the fourth quarter of 2016. The operating losses for the second, third and fourth quarters of 2015 included non-cash full cost impairments of natural gas and oil properties of $1,535 million, $2,839 million and $2,576 million, 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.

SUPPLEMENTAL OIL AND GAS DISCLOSURES (UNAUDITED)

The Company's operating natural gas and oil properties are located solely in the United States. The Company also has licenses to properties in Canada, the development of which is subject to an indefinite moratorium. See "Our Operations — Other — New Brunswick, Canada" in Item 1 of Part 1 of this Annual Report.

Net Capitalized Costs

The following table shows the capitalized costs of natural gas and oil properties and the related accumulated depreciation, depletion and amortization as of December 31, 2016 and 2015:

	2016	2015
	(in millions)	
Proved properties	**$ 20,548**	$ 18,751
Unproved properties	**2,105**	3,727
Total capitalized costs	**22,653**	22,478
Less: Accumulated depreciation, depletion and amortization	**(18,897)**	(16,248)
Net capitalized costs	**$ 3,756**	$ 6,230

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, 2016:

	2016	2015	2014	Prior	**Total**
			(in millions)		
Property acquisition costs	$ 22	$ 213	$ 1,501	$ 54	**$ 1,790**
Exploration and development costs	55	64	24	16	**159**
Capitalized interest	70	55	10	21	**156**
	$ 147	$ 332	$ 1,535	$ 91	**$ 2,105**

Of the total net unevaluated costs excluded from amortization as of December 31, 2016, approximately $1.6 billion is related to the Chesapeake and Statoil Property Acquisitions, approximately $100 million is related to the acquisition of undeveloped properties outside the Appalachian Basin and the Fayetteville Shale, excluding licenses in Canada subject to an indefinite moratorium, and approximately $94 million is related to the acquisition of the Company's undeveloped properties in Northeast Appalachia. Additionally, the Company has approximately $113 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:

	2016	2015	2014
		(in millions, except per Mcfe amounts)	
Proved property acquisition costs	**$ –**	$ 81	$ 1,455
Unproved property acquisition costs	**171**	692	3,934
Exploration costs	**17**	50	232
Development costs	**433**	1,417	1,600
Capitalized costs incurred	**621**	2,240	7,221
Full cost pool amortization per Mcfe	**$ 0.38**	$ 1.00	$ 1.10

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $152 million, $204 million and $55 million during 2016, 2015 and 2014, 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 $112 million, $307 million and $320 million during 2016, 2015 and 2014, 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, which totaled $19 million, $118 million and $123 million during 2016, 2015 and 2014, 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:

	2016	2015	2014
		(in millions)	
Sales	$ 1,413	$ 2,074	$ 2,862
Production (lifting) costs	(839)	(989)	(776)
Depreciation, depletion and amortization	(371)	(1,028)	(884)
Impairment of natural gas and oil properties	(2,321)	(6,950)	–
	(2,118)	(6,893)	1,202
Provision (benefit) for income taxes	– (1)	(2,619)	457
Results of operations (2)	$ (2,118)	$ (4,274)	$ 745

(1) Prior to the Company's recognition of a valuation allowance in 2016, the Company recognized an income tax benefit of $805 million.

(2) Results of operations exclude the gain (loss) on unsettled commodity derivative instruments. See Note 4 - Derivatives and Risk Management

The results of operations shown above exclude general and administrative expenses and interest expense and are not necessarily indicative of the contribution made by the Company's natural gas and oil operations to its consolidated operating results. Income tax expense is calculated by applying the statutory tax rates to the revenues less costs, including depreciation, depletion and amortization, and after giving effect to permanent differences and tax credits.

Natural Gas and Oil Reserve Quantities

The Company engaged the services of Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm, to audit the reserves estimated by the Company's reservoir engineers. In conducting its audit, the engineers and geologists of NSAI studied the Company's major properties in detail and independently developed reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of the Company's major properties, and accounted for approximately 99%, 100% and 97% of the present worth of the Company's total proved reserves as of December 31, 2016, 2015 and 2014, 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 2016, 2015 and 2014, all of which were located in the United States:

	2016			2015			2014		
	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	5,917	8,753	40,947	9,809	37,615	118,699	6,974	373	–
Revisions of previous estimates	(446)	1,564	13,794	(3,458)	(28,394)	(75,664)	542	(14)	66
Extensions, discoveries and other additions	198	2,417	11,576	546	1,367	6,274	1,692	250	48
Production	(788)	(2,192)	(12,372)	(899)	(2,265)	(10,702)	(766)	(235)	(231)
Acquisition of reserves in place	–	–	–	97	525	2,340	1,367	37,246	118,816
Disposition of reserves in place	(15)	(19)	(14)	(178)	(95)	–	–	(5)	–
Proved reserves, end of year	4,866	10,523	53,931	5,917	8,753	40,947	9,809	37,615	118,699
Proved developed reserves:									
Beginning of year	5,474	8,753	40,947	5,675	7,445	38,632	4,237	372	–
End of year	4,789	10,523	53,931	5,474	8,753	40,947	5,675	7,445	38,632
Proved undeveloped reserves:									
Beginning of year	443	–	–	4,134	30,170	80,067	2,737	1	–
End of year	77	–	–	443	–	–	4,134	30,170	80,067

The Company's estimated proved natural gas, oil and NGL reserves were 5,253 Bcfe at December 31, 2016, compared to 6,215 Bcfe at December 31, 2015. The decrease in the Company's reserves in 2016 was primarily due to the decrease in commodity prices. The significant decrease in the Company's reserves in 2015 was primarily due to the decrease in commodity prices. The 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 replaced 550% of its production volumes with proved reserve additions and proved reserve additions as a result of acquisitions primarily associated with acreage in Southwest Appalachia. The following table summarizes the changes in reserves for 2014, 2015 and 2016:

		Appalachia		Fayetteville	
	Total	Northeast	Southwest	Shale	Other [1]
			(in Bcfe)		
December 31, 2013	**6,976**	1,963	–	4,795	218
Production	**(768)**	(254)	(3)	(494)	(17)
Disposition of reserves in place	**–**	–	–	–	–
Acquisition of reserves in place	**2,303**	1	2,300	–	2
Net revisions					
Price revisions	**54**	10	–	38	6
Performance and production revisions	**489**	636	–	(126)	(21)
Total net revisions	**543**	646	–	(88)	(15)
Reserve additions					
Proved developed	**531**	246	–	283	2
Proved undeveloped	**1,162**	589	–	573	–
Total reserve additions	**1,693**	835	–	856	2
December 31, 2014	**10,747**	**3,191**	**2,297**	**5,069**	**190**
Production	**(976)**	(360)	(143)	(465)	(8)
Disposition of reserves in place	**(180)**	–	–	–	(180)
Acquisition of reserves in place	**115**	80	35	–	–
Net revisions					
Price revisions	**(5,718)**	(2,315)	(1,875)	(1,496)	(32)
Performance and production revisions	**1,635**	1,383	209	10	33
Total net revisions	**(4,083)**	(932)	(1,666)	(1,486)	1
Reserve additions					
Proved developed	**416**	202	84	129	1
Proved undeveloped	**176**	138	4	34	–
Total reserve additions	**592**	340	88	163	1
December 31, 2015	**6,215**	**2,319**	**611**	**3,281**	**4**
Production	**(875)**	**(350)**	**(148)**	**(375)**	**(2)**
Disposition of reserves in place	**(15)**	**–**	**(15)**	**–**	**–**
Acquisition of reserves in place	**–**	**–**	**–**	**–**	**–**
Net revisions					
Price revisions	**(1,037)**	**(794)**	**(127)**	**(116)**	**–**
Performance and production revisions	**683**	**318**	**199**	**163**	**3**
Total net revisions	**(354)**	**(476)**	**72**	**47**	**3**
Reserve additions					
Proved developed	**257**	**81**	**157**	**19**	**–**
Proved undeveloped	**25**	**–**	**–**	**25**	**–**
Total reserve additions	**282**	**81**	**157**	**44**	**–**
December 31, 2016	**5,253**	**1,574**	**677**	**2,997**	**5**

(1) Other includes properties outside of the Appalachian Basin and Fayetteville Shale along with Ark-La-Tex properties divested in May 2015.

The Company's December 31, 2016 proved reserves included 77 Bcfe of proved undeveloped reserves from 15 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but do not have a positive present value when discounted at 10%. These properties had a negative present value of $11 million when discounted at 10%. The Company made a final investment decision and is committed to developing these reserves within the next five years from the date of initial booking. The Company's December 31, 2015 proved reserves included 217 Bcfe of proved undeveloped reserves from 75 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but that have a negative $34 million present value when discounted at 10%. The Company's December 31, 2014 proved reserves included 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 that have a negative $28 million present value when discounted at 10%.

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

Standardized Measure of Discounted Future Net Cash Flows

The following standardized measures of discounted future net cash flows relating to proved natural gas, oil and NGL reserves as of December 31, 2016, 2015 and 2014 are calculated after income taxes, discounted using a 10% annual discount rate and do not purport to present the fair market value the Company's proved gas, oil and NGL reserves:

	2016	2015	2014
		(in millions)	
Future cash inflows	$ 9,064	$ 11,887	$ 41,812
Future production costs	(5,880)	(7,376)	(16,477)
Future development costs [1]	(485)	(792)	(5,750)
Future income tax expense [2]	–	–	(4,743)
Future net cash flows	2,699	3,719	14,842
10% annual discount for estimated timing of cash flows	(1,034)	(1,302)	(7,299)
Standardized measure of discounted future net cash flows	$ 1,665	$ 2,417	$ 7,543

(1) Includes abandonment costs.

(2) The December 31, 2016 and 2015 standardized measure computation does not have future income taxes because the Company's tax basis in the associated oil and gas properties exceeded expected pre-tax cash inflows. Future net cash flows are not permitted to be increased by excess tax basis.

Under the standardized measure, future cash inflows were estimated by applying an average price from the first day of each month from the previous 12 months, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Prices used for the standardized measure above were $2.48 per MMBtu for natural gas, $39.25 per barrel for oil and $6.74 per barrel for NGLs in 2016, $2.59 per MMBtu for natural gas, $46.79 per barrel for oil and $6.82 per barrel for NGLs in 2015, and $4.35 per MMBtu for natural gas, $91.48 per barrel for oil and $23.79 per barrel for NGLs in 2014. 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 2016, 2015 and 2014:

	2016	2015	2014
		(in millions)	
Standardized measure, beginning of year	$ 2,417	$ 7,543	$ 3,736
Sales and transfers of natural gas and oil produced, net of production costs	(574)	(1,082)	(2,084)
Net changes in prices and production costs	(415)	(8,075)	1,192
Extensions, discoveries, and other additions, net of future production and development costs	45	162	1,049
Acquisition of reserves in place	–	28	1,897
Sales of reserves in place	(10)	(244)	–
Revisions of previous quantity estimates	(140)	(1,385)	622
Accretion of discount	242	946	513
Net change in income taxes	–	1,915	(522)
Changes in estimated future development costs	71	2,007	110
Previously estimated development costs incurred during the year	114	875	815
Changes in production rates (timing) and other	(85)	(273)	215
Standardized measure, end of year	$ 1,665	$ 2,417	$ 7,543

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act. Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of December 31, 2016 at a reasonable assurance level.

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2016, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting is included on page 84 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 85 of this Annual Report.

ITEM 9B. OTHER INFORMATION

Election of Director

On February 21, 2017, the Board of Directors elected Jon A. Marshall, 65, as a director of the Company effective February 27, 2017, for a term expiring at the 2017 annual meeting of stockholders. With the election of Mr. Marshall, the Board of Directors has nine members.

Mr. Marshall served as President and Chief Operating Officer of Transocean Ltd. from 2007 to 2008 and as the Chief Executive Officer and President of GlobalSantaFe Corporation from 2003 to 2007, when it merged with Transocean. He also served on the boards of directors of those companies. Currently he is a director of Noble Corporation plc (chairman of its HSE & Engineering Committee and member of its Audit and Finance Committees) and of Cobalt International Energy, Inc. (chairman of its Compensation Committee). He is a former chairman of the board of directors of the National Ocean Industries Association. Mr. Marshall received a bachelor of science degree from the United States Military Academy.

The selection of Mr. Marshall was not pursuant to any arrangement or understanding between him and any other person. Mr. Marshall has not been appointed to serve on any standing committees of the Board of Directors and is not expected to be so appointed at this time.

There are no transactions between Mr. Marshall and the Company that are required to be reported under Item 404(a) of Regulation S-K.

In connection with his election, Mr. Marshall will receive a pro rata portion of the annual cash compensation, the equity compensation and the additional compensation amounts received by non-employee directors, which are described in the Company's definitive proxy statement delivered to its stockholders in connection with the 2016 annual meeting of stockholders and filed with the Securities and Exchange Commission on April 6, 2016.

Appointment of Vice President and Controller

On February 21, 2017, effective as of that date, the Board of Directors promoted Colin O'Beirne, 41, to the position of Vice President and Controller and designated him as our principal accounting officer, to serve until the next annual meeting of stockholders and/or until his successor shall be duly elected and shall qualify. In his capacity as the Company's principal accounting officer, Mr. O'Beirne will report to R. Craig Owen, Senior Vice President and Chief Financial Officer, who had reassumed the duties of principal accounting officer on an interim basis beginning in July 2017. Mr. O'Beirne joined the Company in October 2010 as a senior manager over the Company's internal controls and compliance team and, since 2012, has served as a director over various groups within the accounting function. Immediately prior to joining the Company, Mr. O'Beirne was a senior manager at PricewaterhouseCoopers LLP in Houston with over twelve years of accounting and financial reporting experience in the energy industry. Mr. O'Beirne holds a master of science in accounting from Texas A&M University. He is a Certified Public Accountant.

The selection of Mr. O'Beirne was not pursuant to any arrangement or understanding between him and any other person. There is no family relationship between Mr. O'Beirne and any director or executive officer of the Company.

There are no transactions between Mr. O'Beirne and the Company that are required to be reported under Item 404(a) of Regulation S-K.

Other than as disclosed below, we do not have any agreement with Mr. O'Beirne, either written or oral, that guarantees salaries, salary increases, bonuses or benefits. Mr. O'Beirne and the Company will enter into an indemnity agreement and an executive severance agreement to be effective as of the date of his promotion, the forms of which are expected to be consistent with the forms of indemnity agreement incorporated by reference as Exhibit 10.1 to this annual report on Form 10-K and executive severance agreement incorporated by reference as Exhibit 10.2 to this annual report on Form 10-K (as amended by Exhibits 10.3 and 10.4 to this annual report on Form 10-K). The executive severance agreement will entitle him to receive a payment if, within three years after a "Change in Control," (i) his employment is terminated without "Cause" or (ii) he voluntarily terminates employment with the Company for "Good Reason." The severance payment for Mr. O'Beirne will be equal to the product of 2.0 and the sum of base salary as of his termination date plus the maximum bonus opportunity available to him. Mr. O'Beirne also is eligible to participate in the Company's compensation and benefit plans available to executives.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The definitive proxy statement to holders of the Company's common stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Stockholders to be held on or about May 23, 2017 (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 2017 Proxy Statement for discussion of its audit committee and its audit committee financial expert. Information concerning the Company's executive officers is presented in Part I of this Annual Report. The Company refers you to the section "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement for information relating to compliance with Section 16(a) of the Exchange Act.

Code of Business Ethics and Conduct for Directors and Employees

The Company has adopted a code of ethics that applies to its Chief Executive Officer, Chief Financial Officer and Controller as well as other officers and employees. We have posted a copy of our code of ethics on the "Corporate Governance" section of our website at www.swn.com, and it is available free of charge in print to any stockholder who requests it. Requests for copies should be addressed to the Secretary at 10000 Energy Drive, Spring, Texas 77389. Any amendments to, or waivers from, our code of ethics that apply to our executive officers and directors will be posted on the "Corporate Governance" section of our website.

ITEM 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 23, 2017, 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 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 23, 2017, 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 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 23, 2017, 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 2017 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 23, 2017, and is incorporated herein by reference.*

- Except for information or data specifically incorporated by reference under Items 10 through 14, all other information in our 2017 Proxy Statement is not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as part of this report.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) The consolidated financial statements of Southwestern Energy Company and its subsidiaries and the report of independent registered public accounting firm are included in Item 8 of this Annual Report.

(2) The consolidated financial statement schedules have been omitted because they are not required under the related instructions, or are not applicable.

(3) The exhibits listed on the accompanying Exhibit Index are filed as part of, or incorporated by reference into, this Annual Report.

ITEM 16. SUMMARY

None.

SIGNATURES

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

Dated: February 23, 2017	SOUTHWESTERN ENERGY COMPANY 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 23, 2017, on behalf of the Registrant below by the following officers and by a majority of the directors.

/s/ WILLIAM J. WAY William J. Way	Director, President and Chief Executive Officer (Principal executive officer)
/s/ R. CRAIG OWEN R. Craig Owen	Senior Vice President and Chief Financial Officer (Principal financial officer)
/s/ COLIN P. O'BEIRNE Colin P. O'Beirne	Vice President, Controller (Principal accounting officer)
/s/ JOHN D. GASS John D. Gass	Director
/s/ CATHERINE A. KEHR Catherine A. Kehr	Director
/s/ GREG D. KERLEY Greg D. Kerley	Director
/s/ 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 4.95% Notes due 2025. (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
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	First Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 20, 2016)
10.17	Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016)
10.18	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)
10.19	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)

10.20	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)
10.21	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)
10.22	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)
10.23	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)
10.24	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)
10.25	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)
10.26	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)
10.27	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)
10.28	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)
10.29	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)
10.30	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)
10.31	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)
10.32	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)
10.33	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)
10.34	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)
10.35	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)
10.36	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)

10.37	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)
10.38	Retirement Agreement dated January 11, 2016 between Southwestern Energy Company and Steven L. Mueller. (Incorporated by reference to Exhibit 10.38 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2015)
10.39	Retirement Agreement dated May 19, 2016 between Southwestern Energy Company and Jeffrey B. Sherrick. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016)
10.40	Amendment to Awards Agreement dated May 19, 2016 between Southwestern Energy Company and Jeffrey B. Sherrick. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016)
10.41	Amended and Restated Term Loan Credit Agreement, dated June 27, 2016 among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit A to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
10.42	Credit Agreement, dated June 27, 2016 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
10.43	Amendment and Restatement Agreement, dated as of June 27, 2016 among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and the lenders party thereto, giving effect to the Amended and Restated Term Loan Credit Agreement. (Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
10.44	Amendment No. 1 to Credit Agreement, dated as of June 27, 2016 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
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

Forward Looking Statements

This annual report contains forward-looking statements regarding Southwestern Energy Company's future plans and performance based on assumptions the Company believes are reasonable. A number of factors could cause actual results to differ materially from these statements. For further information regarding these factors, see "Cautionary Statement About Forward-Looking Statements" in Management's Discussion and Analysis of Financial Condition and Results of Operations and "Risk Factors" in the Company's 2016 Form 10-K.

Certifications

In 2016, SWN's Chief Executive Officer (CEO) provided to the NYSE the annual CEO certification regarding SWN's compliance with the NYSE's corporate governance listing standards. In addition, SWN's CEO (principal executive officer) and SWN's principal financial officer filed with the United States Securities and Exchange Commission (SEC) all certifications required in SWN's SEC reports for fiscal year 2016.

Annual Meeting

May 23, 2017 at 9:00 a.m. CDT
Southwestern Energy Company
10000 Energy Drive
Spring, TX 77389-4954

Independent Registered Public Accountants

PricewaterhouseCoopers LLP
Houston, TX

Investor Relations

Michael E. Hancock, Director
Investor Relations

Website

www.swn.com

Transfer Agent

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College Station, TX 77842-3170
800.446.2617

By overnight delivery
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College Station, TX 77845

Corporate Headquarters

Southwestern
Energy Company

10000 Energy Drive
Spring, TX 77389-4954

832.796.4700

Non-GAAP Reconciliations

Adjusted Diluted (Loss) Earnings Per Share

	2016	2015	2014	2013	2012
Diluted (loss) earnings per share	$ (6.32)	$ (12.25)	$ 2.62	$ 2.00	$ (2.03)
Add back:					
Participating securities – mandatory convertible preferred stock	--	(0.03)	--	--	--
Impairment of natural gas and oil properties	5.33	18.26	--	--	5.56
Restructuring and other one-time charges	0.20	0.01	--	--	--
Gain on sale of assets, net	--	(0.74)	--	--	--
Loss on early extinguishment of debt and other	0.13	--	--	--	--
Transaction costs	--	0.14	0.01	--	--
Loss (Gain) on certain derivatives	0.86	0.41	(0.37)	(0.06)	0.01
Adjustments due to inventory valuation	0.01	0.08	--	--	--
Adjustments due to discrete tax items	2.25	1.27	(0.13)	0.04	--
Tax impact on adjustments	(2.47)	(6.96)	0.14	0.02	(2.15)
Adjusted diluted (loss) earnings per share	$ (0.01)	$ 0.19	$ 2.27	$ 2.00	$ 1.39

Net Cash Flow (in millions)

	2016	2015	2014	2013	2012
Net cash provided by operating activities	$ 498	$ 1,580	$ 2,335	$ 1,909	$ 1,654
Add back:					
Changes in operating assets and liabilities	99	(112)	(65)	76	(55)
Restructuring charges	48	--	--	--	--
Net cash flow	$ 645	$ 1,468	$ 2,270	$ 1,985	$ 1,599

Adjusted EBITDA (in millions)

	2016	2015	2014	2013	2012
Net income (loss)	$ (2,643)	$ (4,556)	$ 924	$ 704	$ (707)
Add back:					
Depreciation, depletion and amortization	2,757	8,041	942	787	2,751
Gain on sale of assets, net	(3)	(283)	--	--	--
Write-down of inventory	3	32	--	--	--
Loss (Gain) on derivatives excluding derivatives, settled	373	155	(130)	(21)	2
Restructuring and other one-time charges	89	--	--	--	--
Loss on debt extinguishment	51	--	--	--	--
Net interest expense	88	56	59	42	35
Provision (benefit) for income taxes	(29)	(2,005)	525	486	(443)
Adjusted EBITDA	$ 686	$ 1,440	$ 2,320	$ 1,998	$ 1,638

Net Debt (in millions)

	2016	2015	2014
Total debt	$ 4,653	$ 4,705	$ 6,957
Subtract:			
Cash and cash equivalents	(1,423)	(15)	(53)
Net debt	$ 3,230	$ 4,690	$ 6,904

Design: Michael Thede Design LLC Core Principles Summary Photography and Executive Portraits: Ken Childress Photography Printing: Classic Color

swn

Southwestern Energy®

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