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SOUTHWESTERN ENERGY COMPANY

2018 ANNUAL REPORT

REPOSITIONED | REENGINEERED | REENERGIZED

Bill Way
President & CEO

DEAR FELLOW SHAREHOLDERS

2018 was a pivotal year for Southwestern Energy. We refocused, reengineered and reenergized the Company as a leading Appalachia gas and liquids company with an enviable asset base and 45% less debt than at the start of the year while maintaining a value- and returns-driven strategy. We focus on four key areas to deliver long-term value growth:

- We have high quality, large scale assets and a great degree of flexibility from our diverse commodity mix, vertical integration and leading transportation portfolio to maximize value in a volatile market. Our returns-oriented approach allocates capital to the highest value generating projects, with each one required to meet a minimum returns requirements, unhedged.

- We apply an intense focus on increasing capital efficiency and expanding margin to deepen our inventory. Our repositioning to invest in liquid-rich Appalachian Basin projects is testament to this fact.

- We're building a greater and greater share of our cash flow from gas liquids, which enhances our total margin and total revenues. Liquids accounted for approximately 28% of our 2018 revenues from Appalachia production. We've now become one of the major liquids players in the basin and

REPOSITIONED

Premier quality, large scale assets

Appalachia focused

Improved margins, more liquids focused

Multiple bench opportunities

Right-sized access to premium markets

REENGINEERED

Strong and flexible balance sheet

Lower debt

Ample liquidity

Increased **capital efficiency**

Converting **resource to reserves**

Returns focused capital allocation

Continued **rigorous cost management**

REENERGIZED

Leading execution capability

Proven leadership team

Company outperformance

Core value based culture

enjoy the highest condensate yield in the basin due to our super-rich acreage. The ability to flex between commodities adds to our resiliency in what continues to be a volatile commodity environment.

- We remain committed to achieving a sustainable 2X debt-to-EBITDA ratio while investing within cash flow as we transition away from our recently monetized Fayetteville assets. We focus on both components of this ratio. We paid down $2.1 billion in debt in 2018. We plan to grow EBITDA in 2019 and 2020 by supplementing Appalachia cash flow with a portion of the cash proceeds from the Fayetteville monetization. We are doing more with less, driving further cost efficiencies and performance improvements to return to cash flow neutrality by the end of 2020. We adjust investment for market conditions, and we protect the core economics of those investments through a robust rolling three-year hedging program.

We're always generating ways to improve the short-term and long-term value creation from our assets and drive shareholder value. We have a multifaceted approach with a strong focus on organic growth. We're taking actions that are expanding margins and returns in every piece of the business benchmarked against our peers.

As a result of our resource-to-reserves work, we've continued to convert our vast Appalachia resources to proved reserves and grow the breadth and depth of our high-value inventory.

We aim to achieve an industry-leading cost structure — if we don't need it or it doesn't add value, we move on. We leverage our ability to flex activity with pricing to maximize returns in any cost environment. We have a clear agenda of improving efficiency, including longer laterals, reducing costs and improving well productivity. We believe that improved liquidity, favorable leverage, strong cash flow protected with disciplined hedging, ongoing lowering of costs and increasingly efficient operational execution will enhance returns to our investors.

As opportunities or ideas outside of our asset base come to us, we'll evaluate them with the clarity and rigor and discipline that we are known for in our business, and we'll make decisions around them only when we conclude that those benefits can be fully delivered.

Finally, innovation underlies so much of what we do. We innovate in operations and technology to reduce costs and improve margins. We innovate financially to ensure prudent investments at the lowest accessible capital cost. Most important, we innovate in safety and the environment to protect our people and where they live.

2018 HIGHLIGHTS

We successfully monetized the future cash flow from the Fayetteville Shale — both E&P and gathering — raising $1.865 billion before adjustments. In addition to reducing debt, we returned $200 million to shareholders through a share repurchase program that we completed in the first quarter of 2019. The Fayetteville Shale and the people who worked it hold a special place in our hearts and our history. We are grateful for their contributions that have set the stage for a stronger future at Southwestern Energy.

As noted above, in 2018 we strengthened our balance sheet by successfully deleveraging by $2.1 billion and significantly reduced costs, which has improved our financial flexibility. We reported net cash from operating activities of $1.22 billion and net cash flow (a non-GAAP measure) of $1.35 billion, generating $100 million of free cash flow above capital investment. With this enhanced flexibility and completion of the Fayetteville monetization, we expect to realize $150 million in annual savings beginning in 2019. We've reinvented SWN into a leaner, nimbler and more resilient organization that is ever focused on improving our operational and financial performance every day, week and year. We continue to be careful stewards of our shareholders' investments, and we are taking actions every day to increase long-term value.

Our teams are constantly finding new ways to capture even greater value from the assets. We continue to extend horizontal lateral lengths in drilled and completed wells, obtaining more production from a single wellbore. We also have reengineered completion designs to reduce costs and improve well performance. Our water infrastructure, Company-operated drilling rigs and direct sand sourcing are also contributing savings. Our overall well costs in 2018 averaged $1,130 per foot, and we expect to reduce the cost per foot to $875 in 2019. We are cultivating new methodologies within the Data Analytics, Machine Learning, and Artificial Intelligence realm and using them to guide our engineering teams to better solutions, more robust engineering and financial models, and overall greater insight into how our reservoirs work and how to maximize the value of our resource recovery.

CORPORATE RESPONSIBILITY IS A CORE VALUE

"Doing the Right Things" is a part of our Formula. We are determined to operate in a safe, reliable and environmentally sensitive manner that considers our impact on the communities where we live and work. Our employees and contractors strive every day to maintain the trust of their neighbors. Here are a few examples:

- Methane emissions from our Appalachian assets dropped to 0.056% in 2018, which is over 96% lower than the industry average of 1.62%.

- For the third straight year, we were freshwater neutral, removing less water from the local environment than we replaced through recycling or special projects in the same watersheds.

- Our new water delivery pipelines are removing approximately 170,000 truckloads in 2019 from roadways in Pennsylvania and West Virginia.

We are gratified that governmental and non-governmental organizations are recognizing our environmental performance. In particular:

- The Environmental Defense Fund gave the Company a "Leadership Spotlight" in its February 2018 report *Disclosure Divide* for transparent disclosure and continuous improvement on methane emissions.

- Our air emissions reporting in our Corporate Responsibility Report was cited as an example of good Reporting in Practice in *Setting the Bar: Implementing the TCFD Recommendations for Oil and Gas Methane Disclosure*, an October 2018 report by Ceres, the Environmental Defense Fund and PRI.

- We included a Climate Change Scenario Analysis in our 2017-2018 Corporate Responsibility Report.

- The West Virginia Department of Environmental Protection awarded us its top honor for reclamation work on well pad sites in 2017-18.

We have a robust "One Team" safety culture, with our employees and our contractors trained and empowered to stop or modify work and look after one another so that they all get home safely to their families and friends every day. Last year the Company set records in many safety statistics. We will not rest, however, until our incidents fall to zero.

In closing, I want to personally thank all of our employees, who live by these commitments and are the foundation for our progress and the key to our future success.

On behalf of SWN, our board of directors and all of our employees, we sincerely thank you for your continued investment and support.

Sincerely,

Bill Way
President and Chief Executive Officer

FINANCIAL HIGHLIGHTS

Weighted Average Realized Price ($/Mcfe)

2018	**$ 2.66**
2017	$ 2.32
2016	$ 1.62

Net Cash Provided by Operating Activities (in millions)

2018	**$ 1,223**
2017	$ 1,097
2016	$ 498

Capital Investments (in millions)

2018	**$ 1,248**
2017	$ 1,293
2016	$ 648

Diluted Earnings (Loss) Per Share

2018	**$ 0.93**
2017	$ 1.63
2016	$ (6.32)

Adjusted Diluted Earnings (Loss) Per Share[1]

2018	**$ 1.02**
2017	$ 0.44
2016	$ (0.01)

Adjusted EBITDA (in millions)[1]

2018	**$ 1,484**
2017	$ 1,247
2016	$ 721

Production (Bcfe)

2018	**946**
2017	897
2016	875

Reserves (Bcfe)

2018	**11,921**
2017	14,775
2016	5,253

Production Costs ($/Mcfe)[2]

2018	**$ 1.02**
2017	$ 1.00
2016	$ 0.97

Footnotes (1) For the Company's reconciliation of adjusted diluted earnings (loss) per share and adjusted EBITDA to Generally Accepted Accounting Principles, see "Non-GAAP Reconciliations" on the inside back cover. (2) Production cost per Mcfe includes lease operating expenses and production taxes. (3) Proved developed finding and development cost are computed by dividing exploration and development capital costs incurred, excluding capitalized interest and expenses, by PD reserve additions and proved undeveloped conversions.

2018 Proved Developed Finding & Development Cost – $0.70/Mcfe[3]

RESERVES

Increase in reserves value driven by liquids

In 2018, Southwestern Energy's estimated proven natural gas and oil reserves increased seven percent to approximately 11.9 Tcfe, excluding the Fayetteville Shale asset which was sold in December 2018. This increase was achieved primarily through extensions, discoveries and other additions, along with increases in both price and performance revisions in the Appalachian Basin.

Our reserves achieved a pre-tax PV-10 value of $6.5 billion. Our teams have worked on continuing to build upon our inventory in the basin, carefully identifying properties to acquire. We've sharpened our focus on this area, too, seeking to expand into areas where profitable production additions exist.

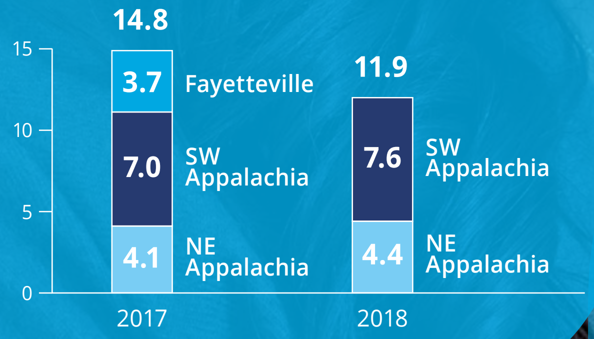
Our proved reserves were comprised of 67% natural gas and 33% liquids compared to 75% natural gas and 25% liquids in 2017, driven by an increase in Southwest Appalachia proved reserves.

The Northeast Appalachia Division and Southwest Appalachia Division combined total reserve life index increased to 17 years at year-end 2018.

As of December 31, 2018, we had 6,364 Bcfe of proved undeveloped reserves, all of which we expect will be developed within five years. During 2018, we invested $491 million to convert 1,096 Bcfe, or 16%, of our proved undeveloped reserves into proved developed reserves. We also added 832 Bcfe of proved undeveloped reserve additions in the Appalachian Basin.

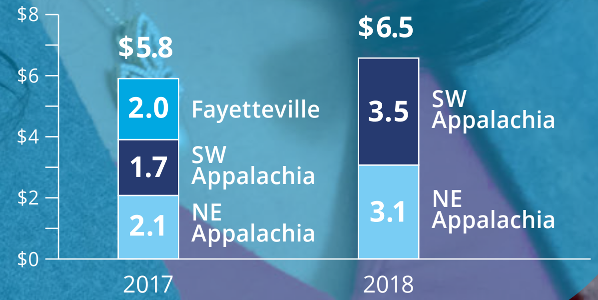
2018 HIGHLIGHTS

Proved Reserves (Tcfe)



NOTE: may not add due to rounding.

Pre-Tax PV10 (in billions)



FINANCIAL STRENGTH & DISCIPLINE

Much stronger position financially with the same sharp focus on achieving attractive returns

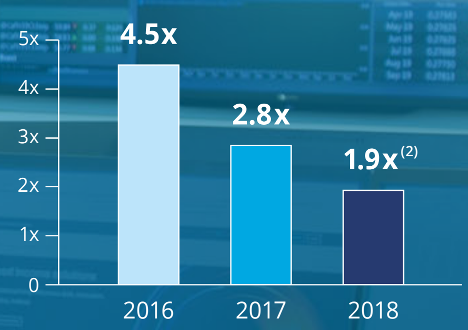
Our balance sheet ended the year in a stronger position, which in turn enabled us to further invest where and how we needed to in order to grow our business. Last year we were able to reduce debt by $2.1 billion and to achieve ongoing annual savings of $150 million per year from reduced interest and organizational costs. We also implemented our first-ever stock buyback, returning about $200 million in value to shareholders.

We are committed to achieving a sustainable 2x debt-to-EBITDA ratio in the future. We are focused on growing EBITDA in the years ahead, by doing more with less, creating further cost efficiencies and performance improvements in order to return to free cash flow by the end of 2020.

We remain focused on demonstrating continued financial discipline and have rescheduled our debt maturities so that we have no significant payments until 2025, thus providing greater financial flexibility.

2018 HIGHLIGHTS

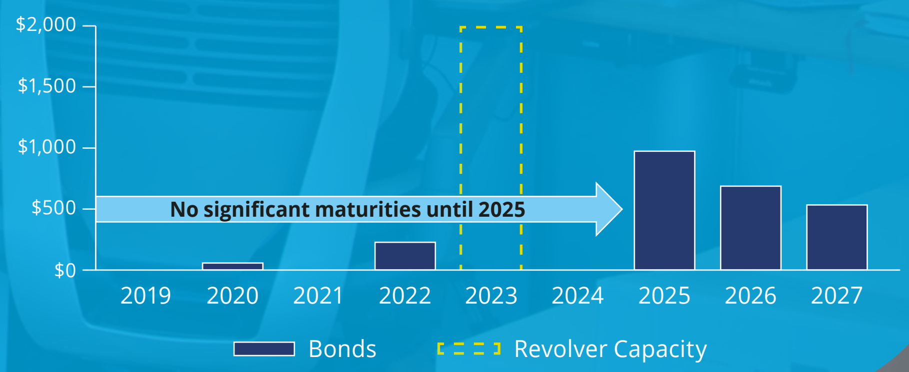
Net Debt / EBITDA[1]



(1) For the Company's reconciliation of net debt and adjusted EBITDA to Generally Accepted Accounting Principles, see "Non-GAAP Reconciliations" on the inside back cover.

(2) Excludes EBITDA generated from Fayetteville prior to December 2018 divestiture.

Debt Maturity Schedule (in millions)



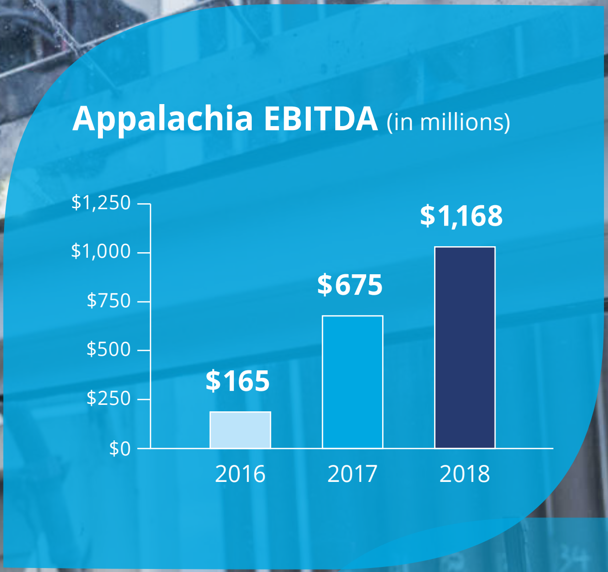
APPALACHIAN BASIN GROWTH STORY

Appalachian Basin continues to grow production, improve margins

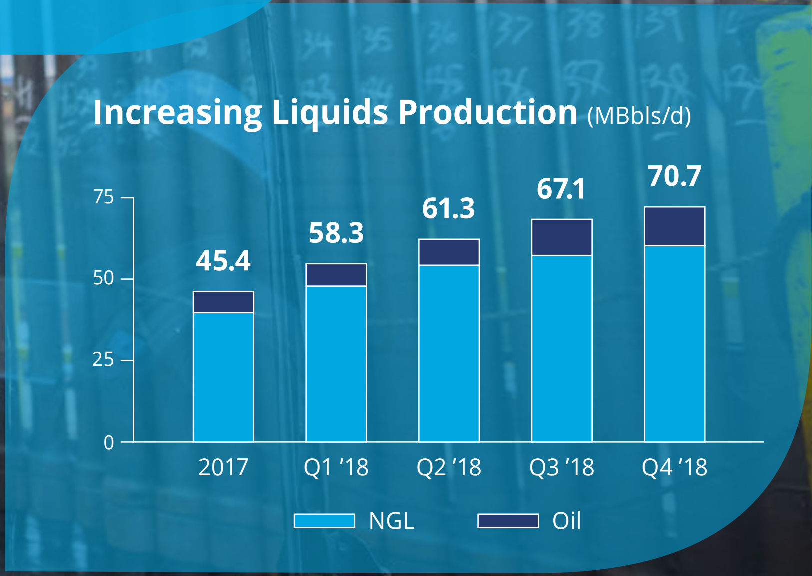
The big news in our Appalachian assets in 2018 was the deliberate move towards more liquids-rich production. We are in the enviable position of being able to shift activity to take advantage of improvements in market pricing, and our moves paid off as higher liquids prices in 2018 increased our overall weighted average realized prices.

In 2018, we had record gross operated exit rate production from our Appalachian Basin assets of 2.75 Bcfe per day, 2.0 Bcfe per day net, a 17% increase compared to December 2017, and we expect these assets to continue to deliver robust value growth in 2019.

With their significant growth potential, our Appalachian Basin assets are well on the path to self-funding.



2018 HIGHLIGHTS



OPERATIONAL EXCELLENCE ADVANCES

Operations continue to improve with less expensive and more innovative solutions

Much like our progress in 2017, we stepped up and delivered further operational efficiencies in our operating areas in 2018. Some key accomplishments included:

- **Improved production** while remaining within original capital program guidance.
- **Established record production levels** in both NE Appalachia and SW Appalachia.
- **Grew liquids production above the forecasted level,** which incrementally added value with improved liquids pricing.
- **Extended lateral lengths in Appalachia Divisions;** successfully drilled record laterals in both areas.
- **Improved safety performance** in drilling, completions, facilities and production operations.
- **Improved operational execution and efficiencies** (cycle-time improvements, cost reductions such as direct sand sourcing).
- **Advanced water projects in SW Appalachia and NE Appalachia** to reduce well costs in 2019 and beyond.

In 2018, we continued to make improvements in the performance of our Appalachian Basin assets with a primary focus on enhancing margins. During 2018, we executed on this part of our business strategy by:

- **Lowering our costs** through drilling, completions and operational efficiencies and optimizing gathering and transportation costs.
- Delivering operational excellence with **improved well productivity and economics** from enhanced completion techniques, initiation of water infrastructure projects, optimization of surface equipment and managing reservoir drawdown.
- **Expanding our proved reserve quantities** in the Appalachian Basin through our successful drilling program, improved operational performance and improved commodity prices.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Southwestern Energy

ENVIRONMENTAL RESPONSIBILITY

SWN has an unyielding commitment to environmental responsibility

Our environmental efforts have yielded awards and recognition from state agencies, community leaders and industry organizations. While delivering improved well productivity and economics, we also continue to deliver on our commitments to proactively pursue environmentally responsible practices throughout our operations, and thus assure their sustainability.

SWN is a leader in implementing technologies to reduce methane emissions in our operations. We believe in a science-based approach to collect real-world data and adopt process improvements that result in true emission reductions for our operating practices.

We proactively implement methane mitigation technologies, including reduced methane emissions completions, pneumatic device replacement, emission minimization during liquids unloading, and our leak detection and repair (LDAR) program. Many of these measures are done well in advance of regulatory requirements. Taking these actions makes good business sense for operational efficiency, as well as reinforcing our dedication to environmental sustainability.

In 2018, we continued to exceed our goal to maintain a methane intensity commitment of 0.28% as part of our membership in the ONE (Our Nation's Energy) Future coalition. Our 2018 year-end rate was 0.056%, well below the coalition goal.

We are proud to be in our third year as a freshwater neutral company. Meaning, for every gallon of fresh water we use in our operations, we return at least that much to the environment through conservation projects in the basins in which we operate.

In 2018*, we had nine fully functioning conservation projects in our three active basins providing over three billion gallons of freshwater benefits to the environment. These projects, such as impaired stream restoration or treatment of acid mine drainage, provide lasting benefits to the environment and communities which today are hosting our operations.

There is no company in our industry that can prosper if it doesn't have a strong commitment to being a safe and responsible operator. We've built this into the fabric of our corporate culture, and we continue to make steady progress toward achieving our safety and environmental goals.

*SWN sold the Fayetteville asset in December, 2018.

Executive Officers

From left to right: **John C. Ale** (5), Senior Vice President–General Counsel and Secretary; **J. David Cecil** (1), Executive Vice President–Corporate Development; **Jennifer N. McCauley** (9), Senior Vice President–Administration; **Julian M. Bott** (1), Executive Vice President and Chief Financial Officer; **William J. Way** (7), President and Chief Executive Officer; **Clayton A. Carrell** (1), Executive Vice President and Chief Operating Officer; **Jennifer E. Stewart** (8), Senior Vice President–Government and Regulatory Affairs; **R. Jason Kurtz** (21), Vice President–Marketing and Transportation

Directors

William J. Way (3)
President and
Chief Executive Officer

John D. Gass (6)
Retired–
Chevron Corporation

Greg D. Kerley (8)
Retired CFO–Southwestern
Energy Company

Terry W. Rathert (4)
Retired–Newfield
Exploration Company

Catherine A. Kehr (7)
Retired–The Capital
Group Companies

Patrick M. Prevost (1)
Retired–
Cabot Corporation

Jon A. Marshall (1)
Retired–
Transocean Ltd.

Anne Taylor (*)
Retired–
Deloitte

Gary P. Luquette (1)
Retired–
Frank's International N.V.

Corporate Officers

William J. Way (7)
President and
Chief Executive
Officer

Clayton A. Carrell (1)
Executive Vice
President and Chief
Operating Officer

Julian M. Bott (1)
Executive Vice
President and Chief
Financial Officer

J. David Cecil (1)
Executive Vice
President–Corporate
Development

John C. Ale (5)
Senior Vice President–
General Counsel
and Secretary

Jennifer N. McCauley (9)
Senior Vice President–
Administration

Jennifer E. Stewart (8)
Senior Vice President–
Government and
Regulatory Affairs

Colin P. O'Beirne (8)
Vice President
and Controller

Randall L. Barron (16)
Vice President
and Treasurer

Michael E. Hancock (8)
Vice President–Financial
Planning and Analysis

C. Paige Penchas (1)
Vice President–
Investor Relations

Carina L. Gillenwater (*)
Vice President–
Human Resources

Andrew T. Huggins (11)
Vice President–
Commercial
Development

Seema Menon (8)
Vice President–
Business Information
Services

Operating Subsidiary Officers

R. Jason Kurtz (21)
Vice President–
Marketing
and Transportation

Ron E. Hyden (5)
Vice President–
Technology

John P. Kelly Jr. (1)
Senior Vice President–
Northeast
Appalachia Division

William Q. Dyson (1)
Vice President–
Operations Services

Derek W. Cutright (10)
Senior Vice President–
Southwest
Appalachia Division

Harry H. "Sonny" Bryan (18)
Vice President–
Technical and
Operational Excellence

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.

For Executive Officers, years with the Company 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, 2018**

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

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

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

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

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

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

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

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging Growth Company ☐

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

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was $3,096,452,639 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2018 of $5.30. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 26, 2019, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 541,319,293.

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 21, 2019 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, 2018

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This Annual Report on Form 10-K ("Annual Report") 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, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those forms filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge as soon as reasonably practicable after they are filed with the Securities and Exchange Commission, or SEC, on our website at www.swn.com. Our corporate governance guidelines and the charters of the Audit, the Compensation, the Health, Safety, Environment and Corporate Responsibility and the Nominating and Governance Committees of our Board of Directors are available on our website, and, upon request, in print free of charge to any stockholder. Information on our website is not incorporated into this report.

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

ITEM 1. BUSINESS

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

Southwestern, which is currently incorporated in Delaware, 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 Tunkhannock, Pennsylvania and Morgantown, West Virginia.

Our Business Strategy

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

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

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 skills, which we believe will grow long-term value for our shareholders. The arrow in our formula is not a straight line: we acknowledge that factors may adversely affect quarter-by-quarter results, but the path over time points to value creation.

In applying these core principles, we concentrate on:

- ***Financial Strength.*** We are committed to rigorously managing our balance sheet and financial risks. We budget to invest from our net cash flow from operations, supplemented over the next two years by a portion of the proceeds from our recent asset sales. Additionally, we protect our projected cash flows through hedging and continue to maintain a strong balance sheet with ample liquidity.
- ***Increasing Margins.*** We apply strong technical, operational, commercial and marketing skills to reduce costs, improve the productivity of our wells and pursue commercial arrangements to extract greater value. We believe our demonstrated ability to improve margins, especially by leveraging the scale of our large assets, gives us a competitive advantage as we move into the future.
- ***Exercising Capital Allocation Discipline.*** We continually assess market conditions in order to adjust our capital allocation decisions to maximize shareholder returns. This allocation process includes consideration of multiple alternatives including but not limited to the development of our natural gas and oil assets, strategic acquisitions, reducing debt and returning capital to our shareholders.
- ***Operational Value Creation.*** We prepare an economic analysis for our drilling programs and other investments based upon the expected net present value added for each dollar to be invested, which we refer to as Present Value Index, or PVI. We target projects that generate the highest returns in excess of our cost of capital. This disciplined investment approach governs our investment decisions at all times, including the current lower-price commodity market.
- ***Dynamic Management of Assets Throughout Life Cycle.*** We own large-scale, long-life assets in various phases of development. In early stages, we ramp up development through technical, operational and commercial skills, and as they grow we look for ways to maximize their value through efficient operating practices along with applying our 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 believe that our vertical integration enhances our margins and provides us competitive advantages. For example, we own and operate drilling rigs and well stimulation equipment and are investing in a water transportation project in West Virginia, a portion of which is already in service and providing approximately $0.5 million in savings per well. These activities provide operational flexibility, help protect our margin, lower our well costs, minimize the risk of unavailability of these resources from third parties and capture additional value.
- ***Technological Innovation.*** 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.
- ***Environmental Solutions and Policy Formation.*** We are a leader in identifying and implementing innovative solutions to unconventional hydrocarbon development to minimize the environmental and community impacts of our activities. We work extensively with governmental, non-governmental and industry stakeholders to develop responsible and cost-effective programs. We demonstrate that a company can operate responsibly and profitably, putting us in a better position to comply with new regulations as they evolve.

In recent years, we have faced a challenging commodity price environment that has impacted our revenues and margins. As a result, we implemented a series of strategic initiatives, which were designed to reposition our portfolio to increase operational and financial flexibility, stabilize the Company financially and improve operational performance.

Repositioning of Our Portfolio

During 2018, we completed the next phase of strategic steps, designed to reposition our portfolio, which allowed us to sharpen our focus on our assets with the highest return. We believe that, in doing so, we will further strengthen our balance sheet and enhance our financial performance. These initiatives included:

- Completing the sale of 100% of the equity in certain of our subsidiaries that conducted our operations in Arkansas, which were primarily focused on the Fayetteville Shale (the “Fayetteville Shale sale”);
- Responding to commodity price changes by shifting focus to our liquids-rich portfolio in Southwest Appalachia; and
- Utilizing a portion of funds realized from the Fayetteville Shale sale to reduce debt and return capital to shareholders. We intend to use the remaining funds to further develop our Appalachian Basin assets in order to accelerate the path to self-funding and for general corporate purposes.

Financial Stability

During 2018, we focused on enhancing our financial stability by:

- Continuing to invest only in those projects that meet our rigorous economic hurdles at strip pricing, adjusting for basis differentials;
- Demonstrating financial discipline by investing within our announced plan of cash flow;
- Identifying and implementing structural, process and organizational changes to further reduce general and administrative costs; and
- Simplifying our capital structure by consolidating the components of our previous credit arrangements into a single senior secured revolving credit facility while increasing liquidity, extending our maturity profile and reducing interest expense.

Operational Improvement

We improved the performance of our large asset portfolio with a primary focus on enhancing margins and investment returns. During 2018, we executed on this part of our business strategy by:

- Lowering our costs through drilling, completions and operational efficiencies and optimizing gathering and transportation costs;
- Focusing on delivering operational excellence with improved well productivity and economics from enhanced completion techniques, initiation of water infrastructure projects, optimization of surface equipment and managing reservoir drawdown; and

- Expanding our proved reserve quantities in the Appalachian Basin through our successful drilling program, improved operational performance and improved commodity prices.

The bulk of our operations, which we refer to as Exploration and Production ("E&P"), are focused on the finding and development of natural gas, oil and NGL reserves. We are also focused on creating and capturing additional value through our marketing business and, until the Fayetteville Shale sale, natural gas gathering, all of which we historically have referred to as Midstream.

Exploration and Production

Overview

Our primary business is the exploration for, and production of, natural gas, oil and NGLs, with our current operations solely within the United States. We are currently focused on the development of unconventional natural gas reservoirs located in Pennsylvania and West Virginia. Our operations in northeast Pennsylvania (herein referred to as "Northeast Appalachia") are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale, and our 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, oil and NGL reservoirs. Collectively, our properties located in Pennsylvania and West Virginia are herein referred to as the "Appalachian Basin."

- Our E&P segment recorded operating income of $794 million in 2018, compared to $549 million in 2017. Our E&P segment operating income increased $245 million in 2018 from 2017 primarily due to a $439 million increase in revenues, partially offset by a $194 million increase in operating expenses due primarily to increased gathering and processing fees resulting from a shift in our production growth to the Appalachian Basin.
- Cash flow from operations from our E&P segment was $1.4 billion in 2018, compared to $985 million in 2017. Our cash flow from operations increased in 2018 as the effects of higher realized prices and increased production volumes more than offset increased operating expenses associated with higher liquids activity.

On August 30, 2018, we announced our entry into an agreement to effect the Fayetteville Shale sale. The Fayetteville Shale sale closed on December 3, 2018 resulting in net proceeds of approximately $1,650 million, following adjustments of $215 million primarily related to the net cash flows from the economic effective date to the closing date and certain other working capital adjustments.

Oilfield Services Vertical Integration

We provide certain oilfield services that are strategic and economically beneficial for our E&P operations when our E&P activity levels and market pricing support these activities. This vertical integration lowers our net well costs, allows us to operate efficiently and helps us to mitigate certain operational and environmental risks. These services have included drilling, hydraulic fracturing and water management and movement.

As of December 31, 2018, we had seven drilling rigs and two leased pressure pumping spreads with a total capacity of approximately 72,000 horsepower. These assets provide us greater flexibility to align our operational activities with commodity prices. In 2018, we provided drilling rigs for all of our 106 drilled wells. In addition, we provided hydraulic fracturing services utilizing one pressure pumping spread in Southwest Appalachia.

Our Proved Reserves

	For the years ended December 31, 2018	2017	2016
Proved reserves: *(Bcfe)*			
Appalachian Basin	11,920	11,088	2,251
Fayetteville Shale	–	3,679	2,997
Other	1	8	5
Total proved reserves	11,921	14,775	5,253
Prices used:			
Natural gas *(per Mcf)*	$ 3.10	$ 2.98	$ 2.48
Oil *(per Bbl)*	65.56	47.79	39.25
NGL *(per Bbl)*	17.64	14.41	6.74
PV-10: *(in millions)*			
Pre-tax	$ 6,524	$ 5,784	$ 1,665
PV of taxes	(525)	(222)	–
After-tax	$ 5,999	$ 5,562	$ 1,665
Percent of estimated proved reserves that are:			
Natural gas	67%	75%	93%
Proved developed	47%	54%	99%
Percent of operating revenues generated by natural gas sales	78%	85%	89%

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 respective commodity price used in our reserve and after-tax PV-10 calculations.

- Our reserves decreased in 2018, compared to 2017, primarily due to the sale of our Fayetteville Shale E&P assets. Excluding the impact of the Fayetteville Shale sale, our reserves increased 7% in 2018, compared to 2017, primarily through extensions, discoveries and other additions, along with increases in both price and performance revisions in the Appalachian Basin.
- The increase in our reserves in 2017 compared to 2016 was primarily due to extensions, discoveries and other additions in the Appalachian Basin along with increases in both price and performance revisions across our portfolio.
- The increase in our after-tax PV-10 value in 2018 compared to 2017 was primarily due to increases in both price and performance revisions in our Appalachian Basin. Excluding the impact of the Fayetteville Shale sale, the increases in our after-tax PV-10 value in both 2018 and 2017, compared to the respective prior years, was primarily due to higher prices and higher reserve levels, including an increasingly larger percentage of oil and NGL reserves.
- We are the designated operator of approximately 99% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index was approximately 17.0 years at year-end 2018, excluding the production from the Fayetteville Shale.

The difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2018 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 after-tax PV-10 computation did not have future income taxes because our tax basis in the associated natural gas and oil properties exceeded expected pre-tax cash inflows, and thus did 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 that include uncertainties. Any material change to these uncertainties or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A of Part I of this Annual Report, and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

The following table provides an overall and categorical summary of our natural gas, oil and NGL reserves, as of fiscal year-end 2018 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2018, and sets forth 2018 annual information related to production and capital investments for each of our operating areas:

2018 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA (1)

	Appalachia			
	Northeast	Southwest	Other (2)	Total
Estimated proved reserves:				
Natural gas *(Bcf)*:				
Developed	3,327	1,068	–	4,395
Undeveloped	1,039	2,610	–	3,649
	4,366	3,678	–	8,044
Crude oil *(MMBbls)*:				
Developed	–	17.9	0.1	18.0
Undeveloped	–	51.0	–	51.0
	–	68.9	0.1	69.0
Natural gas liquids *(MMBbls)*:				
Developed	–	175.5	–	175.5
Undeveloped	–	401.6	–	401.6
	–	577.1	–	577.1
Total proved reserves *(Bcfe)* (3):				
Developed	3,327	2,229	1	5,557
Undeveloped	1,039	5,325	–	6,364
	4,366	7,554	1	11,921
Percent of total	37%	63%	0%	100%
Percent proved developed	76%	30%	100%	47%
Percent proved undeveloped	24%	70%	0%	53%
Production *(Bcfe)*	459	243	244 (4)	946
Capital investments *(in millions)*	$ 422	$ 691	$ 118 (5)	$ 1,231
Total gross producing wells (6)	666	466	17	1,149
Total net producing wells (6)	592	333	14	939
Total net acreage	184,024	297,445	166,120 (7)	647,589
Net undeveloped acreage	73,174	220,331	153,159 (7)	446,664
PV-10:				
Pre-tax *(in millions)* (8)	$ 3,054	$ 3,470	$ –	$ 6,524
PV of taxes *(in millions)* (8)	(245)	(280)	–	(525)
After-tax *(in millions)* (8)	$ 2,809	$ 3,190	$ –	$ 5,999
Percent of total	47%	53%	0%	100%
Percent operated (9)	99%	100%	100%	99%

(1) The Fayetteville Shale E&P assets and associated reserves were divested on December 3, 2018.

(2) Other reserves and acreage consists primarily of properties in Colorado. Production and capital investing includes Fayetteville Shale.

(3) 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.

(4) Includes 243 Bcf of natural gas production related to our Fayetteville Shale operations which were sold on December 3, 2018.

(5) Other capital investments includes $33 million related to our Fayetteville Shale operations which were sold on December 3, 2018, $60 million related to our water infrastructure project, $16 million related to our E&P service companies and $9 million related to our exploration activities.

(6) Represents producing wells, including 394 wells in which we only have an overriding royalty interest in Northeast Appalachia, used in the December 31, 2018 reserves calculation.

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

(8) 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.

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

Lease Expirations

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

	For the years ended December 31,		
Net acreage expiring:	2019	2020	2021
Northeast Appalachia	7,429 [3]	3,857	1,837
Southwest Appalachia [1]	21,761 [3]	14,630	6,701
Other			
US – Other Exploration	87,498	30,686	9,032
US – Sand Wash Basin	5,761	989	7
Canada – New Brunswick [2]	–	–	2,518,519

(1) Of this acreage, 9,410 net acres in 2019, 5,300 net acres in 2020 and 2,647 net acres in 2021 can be extended for an average of 4.8 years.

(2) Exploration licenses were extended through 2021 but have been subject to a moratorium since 2015.

(3) We have no reported proved undeveloped locations expiring in 2019.

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 that include uncertainties. Any material changes to these uncertainties 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 2016, 2017 and 2018:

CHANGES IN PROVED UNDEVELOPED RESERVES

	Appalachia		Fayetteville		
(Bcfe)	Northeast	Southwest	Shale [1]	Other [2]	**Total**
December 31, 2015	**314**	**4**	**125**	**–**	**443**
Extensions, discoveries and other additions	–	–	25	–	**25**
Performance and production revisions [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**
Extensions, discoveries and other additions [4]	1,100	5,186	543	–	**6,829**
Performance and production revisions [3]	–	6	(14)	–	**(8)**
Price revisions	2	–	1	–	**3**
Developed	(17)	–	(29)	–	**(46)**
Disposition of reserves in place	–	–	–	–	**–**
Acquisition of reserves in place	–	–	–	–	**–**
December 31, 2017	**1,119**	**5,192**	**544**	**–**	**6,855**
Extensions, discoveries and other additions	**397**	**435**	**–**	**–**	**832**
Performance and production revisions [3]	**39**	**217**	**–**	**–**	**256**
Price revisions	**8**	**53**	**–**	**–**	**61**
Developed	**(524)**	**(572)**	**–**	**–**	**(1,096)**
Disposition of reserves in place	**–**	**–**	**(544)**	**–**	**(544)**
Acquisition of reserves in place	**–**	**–**	**–**	**–**	**–**
December 31, 2018	**1,039**	**5,325**	**–**	**–**	**6,364**

(1) The Fayetteville Shale E&P assets and associated reserves were sold on December 3, 2018.

(2) Other includes properties principally in Colorado.

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

(4) The 2017 proved undeveloped, or PUD, additions of 6,829 Bcfe were comprised of 3,910 Bcfe attributable to adding new undeveloped locations throughout the year through our successful drilling program and 2,919 Bcfe attributable to adding undeveloped locations associated with increased commodity pricing across our portfolio.

Performance, production and price revisions consist of revisions to reserves associated with wells having proved reserves in existence as of the beginning of the year. Extensions, discoveries and other additions include new reserves locations added in the current year.

- As of December 31, 2018, we had 6,364 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 2018, we invested $491 million in connection with converting 1,096 Bcfe, or 16%, of our proved undeveloped reserves as of December 31, 2017 into proved developed reserves and added 832 Bcfe of proved undeveloped reserve additions in the Appalachian Basin. Proved undeveloped reserves also decreased in 2018 primarily due to the sale of the Fayetteville Shale E&P assets.
- As of December 31, 2017, we had 6,855 Bcfe of proved undeveloped reserves. During 2017, we invested $23 million in connection with converting 46 Bcfe, or 60%, of our proved undeveloped reserves as of December 31, 2016 into proved developed reserves and added 6,829 Bcfe of proved undeveloped reserve additions in the Appalachian Basin. The significant increase in our proved undeveloped reserve additions in 2017 was the result of adding new undeveloped locations throughout the year through our successful drilling program, improved operational performance and increased commodity pricing across our portfolio.
- As of December 31, 2016, we had 77 Bcfe of proved undeveloped reserves. During 2016, we invested $103 million in connection with converting 220 Bcfe, or 50%, of our proved undeveloped reserves as of December 31, 2015 into proved developed reserves and added 25 Bcfe of proved undeveloped reserve additions in the Fayetteville Shale. As a result of the commodity price environment in 2016, we had downward price revisions of 374 Bcfe which were slightly offset by a 203 Bcfe increase due to performance revisions.

Our December 31, 2018 proved reserves included 190 Bcfe of proved undeveloped reserves from 30 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 $24 million when discounted at 10%. We have made a final investment decision and are committed to developing these reserves within five years from the date of initial booking.

We expect that the development costs for our proved undeveloped reserves of 6,364 Bcfe as of December 31, 2018 will require us to invest an additional $3.8 billion for those reserves to be brought to production. Our ability to make the necessary investments to generate these cash inflows is subject to factors that may be beyond our control. The current commodity price environment has resulted, and could continue to result, in certain reserves no longer being economic to produce, leading to both lower proved reserves and cash flows. We refer you to the risk factors "Natural gas, oil and NGL 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

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

In 2018, we replaced 162% of our production volumes with 1,009 Bcfe of proved reserve additions and net upward revisions of 526 Bcfe, essentially all of which were from the Appalachian Basin. Excluding the production from our Fayetteville Shale assets which were divested on December 3, 2018, we replaced 218% of our production in 2018. The following table summarizes the changes in our proved natural gas, oil and NGL reserves for the year ended December 31, 2018:

	Appalachia		Fayetteville		
(in Bcfe)	Northeast	Southwest	Shale [(1)]	Other [(2)]	**Total**
December 31, 2017	**4,126**	**6,962**	**3,679**	**8**	**14,775**
Net revisions					
Price revisions	41	106	6	1	**154**
Performance and production revisions	107	272	(6)	(1)	**372**
Total net revisions	148	378	–	–	**526**
Extensions, discoveries and other additions					
Proved developed	154	22	1	–	**177**
Proved undeveloped	397	435	–	–	**832**
Total reserve additions	551	457	1	–	**1,009**
Production	(459)	(243)	(243)	(1)	**(946)**
Acquisition of reserves in place	–	–	–	–	**–**
Disposition of reserves in place	–	–	(3,437)	(6)	**(3,443)**
December 31, 2018	**4,366**	**7,554**	**–**	**1**	**11,921**

(1) The Fayetteville Shale E&P assets and associated reserves were divested December 3, 2018.

(2) Other includes properties outside of the Appalachian Basin and Fayetteville Shale.

Our ability to add reserves depends upon many factors that are beyond our control. We refer you to the risk factors "Significant capital expenditures are required to replace our reserves and conduct our business" and "If we are not able to replace reserves, we may not be able to grow or sustain production." in Item 1A of Part I of this Annual Report and to "Management's Discussion and Analysis of Financial Condition and Results of Operations – Cautionary Statement about Forward-Looking Statements" in Item 7 of Part II of this Annual Report for a more detailed discussion of these factors and other risks.

Our Operations

Northeast Appalachia

Northeast Appalachia represented 49% of our total 2018 net production and 37% of our total reserves as of December 31, 2018. In 2018, our reserves in Northeast Appalachia increased by 240 Bcf, which included net additions of 551 Bcf, net upward price revisions of 41 Bcf and net upward performance revisions of 107 Bcf, partially offset by production of 459 Bcf. As of December 31, 2018, we had approximately 184,024 net acres in Northeast Appalachia and had spud or acquired 680 operated wells, 597 of which were on production. Below is a summary of Northeast Appalachia's operating results for the latest three years:

	For the years ended December 31,		
	2018	2017	2016
Acreage			
Net undeveloped acres	**73,174** (1)	87,927 (2)	146,096
Net developed acres	**110,850**	103,299	99,709
Total net acres	**184,024**	191,226	245,805
Net Production *(Bcf)*	**459**	395	350
Reserves			
Reserves *(Bcf)*	**4,366**	4,126	1,574
Locations:			
Proved developed producing	**1,042**	983	820
Proved developed non-producing	**21**	25	39
Proved undeveloped	**82**	100 (3)	2
Total locations (4)	**1,145**	1,108	861
Gross Operated Well Count Summary			
Spud or acquired	**35**	58	32
Completed	**54**	77	33
Wells to sales	**60**	83	24
Capital Investments *(in millions)*			
Exploratory and development drilling, including workovers	**$ 370**	$ 420	$ 160
Acquisition and leasehold	**14**	14	3
Seismic and other	**3**	13	2
Capitalized interest and expense	**35**	42	39
Total capital investments	**$ 422**	$ 489	$ 204
Average completed well cost *(in millions)*	**$ 7.5**	$ 5.9	$ 5.3
Average lateral length *(feet)*	**7,584**	6,185	6,142

(1) Our undeveloped acreage position as of December 31, 2018 had an average royalty interest of 15%.

(2) The decrease in our net undeveloped acres in 2017 as compared to 2016 is due to leasehold expirations in areas we did not plan on developing.

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

(4) Includes 394 proved developed producing and 10 proved developed non-producing wells in which we only have an overriding royalty interest.

For 2018 as compared to 2017:

- Our average completed well cost increased primarily due to the drilling of longer lateral wells, new infrastructure due to increased activity in delineation areas and more complex hydraulic fracturing designs.

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

Southwest Appalachia

Southwest Appalachia represented 26% of our total 2018 net production and 63% of our total reserves as of December 31, 2018. In 2018, our reserves in Southwest Appalachia increased by 592 Bcfe, which included net additions of 457 Bcfe, net upward price revisions of 106 Bcfe and 272 Bcfe of net upward performance revisions, partially offset by production of 243 Bcfe. As of December 31, 2018, we had approximately 297,445 net acres in Southwest Appalachia and had a total of 436 wells on production that we operated. Below is a summary of Southwest Appalachia's operating results for the latest three years:

	For the years ended December 31,		
	2018	2017	2016
Acreage			
Net undeveloped acres	**220,331** (1)	219,709	252,470
Net developed acres	**77,114**	70,582	69,093
Total net acres	**297,445**	290,291	321,563
Net Production			
Natural gas *(Bcf)*	**105**	85	62
Oil *(MBbls)*	**3,355**	2,228	2,041
NGL *(MBbls)*	**19,679**	14,193	12,317
Total production *(Bcfe)* (2)	**243**	183	148
Reserves			
Reserves *(Bcfe)*	**7,554**	6,962	677
Locations:			
Proved developed	**423**	364	306
Proved developed non-producing	**45**	37	44
Proved undeveloped	**488**	559 (3)	–
Total locations	**956**	960	350
Gross Operated Well Count Summary			
Spud or acquired	**62**	55	17
Completed	**63**	50	17
Wells to sales	**76**	57	18
Capital Investments *(in millions)*			
Exploratory and development drilling, including workovers	**$ 502**	$ 353	$ 111
Acquisition and leasehold	**37**	59	18
Seismic and other	**4**	4	1
Capitalized interest and expense	**148**	131	158
Total capital investments (4)	**$ 691**	$ 547	$ 288
Average completed well cost *(in millions)* (5) (6)	**$ 9.2**	$ 7.4	$ 5.4
Average lateral length *(feet)* (5) (6)	**7,267**	7,451	5,275

(1) Our undeveloped acreage position as of December 31, 2018 had an average royalty interest of 14%.

(2) Approximately 240 Bcfe, 179 Bcfe and 148 Bcfe for the years ended December 31, 2018, 2017 and 2016, respectively, were produced from the Marcellus Shale formation.

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

(4) Excludes $60 million and $37 million for the years ended December 31, 2018 and 2017, respectively, related to our water infrastructure project.

(5) Includes only wells drilled by the Company.

(6) Average completed well cost and average lateral length for the years ended December 31, 2018, 2017 and 2016 include Marcellus wells only and exclude three Upper Devonian wells in 2018 and one Utica well in 2017 and 2016.

For 2018 as compared to 2017:

- Our average completed well cost increased primarily due to increased completion intensity and larger facilities associated with our liquid-rich wells. The higher well costs are offset by higher liquid production and revenues. In 2018, our NGL and oil production increased by 38% and 46%, respectively, as compared to prior year.

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

Fayetteville Shale

On August 30, 2018, we entered into an agreement to effect the Fayetteville Shale sale for $1,865 million, subject to customary adjustments. In early December 2018, we completed the Fayetteville Shale sale, resulting in net proceeds of $1,650 million, following adjustments due primarily to the net cash flows from the economic effective date of July 1, 2018, to the closing date.

Production in the Fayetteville Shale totaled 243 Bcf for the year ended December 31, 2018, which represented 26% of our total 2018 net production. In 2018, we invested $33 million in the Fayetteville Shale.

Other

Excluding 2,518,519 acres in New Brunswick, Canada, which have been subject to a government-imposed drilling moratorium since 2015, we held 153,159 net undeveloped acres for the potential development of new resources as of December 31, 2018. This compares to 369,236 net undeveloped acres held at year-end 2017 and 492,389 net undeveloped acres held at year-end 2016, excluding the New Brunswick acreage.

We limited our activities in areas beyond our assets in the Appalachian Basin and the Fayetteville Shale during 2018, 2017 and 2016 as a result of the commodity price environment as we focused our capital allocation on these more economically competitive plays. There can be no assurance that any prospects outside of our development plays will result in viable projects or that we will not abandon our initial investments.

New Brunswick, Canada. We currently hold exclusive licenses to search and conduct an exploration program covering 2,518,519 net acres in New Brunswick. 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 2016.

Acquisitions and Divestitures

On August 30, 2018, we entered into an agreement to effect the Fayetteville Shale sale for $1,865 million, subject to customary adjustments. In early December 2018, we completed the Fayetteville Shale sale, receiving $1,650 million in net proceeds after adjustments to the purchase price of $215 million primarily due to the net cash flows from the economic effective date of July 1, 2018 to the closing date.

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

Capital Investments

(in millions)	For the years ended December 31, 2018	2017	2016
E&P Capital Investments by Type			
Exploratory and development drilling, including workovers	$ 895	$ 878	$ 358
Acquisition and leasehold	51	86	23
Seismic expenditures	4	7	1
Water infrastructure project	60	37	–
Drilling rigs, sand facility, and other	15	28	2
Capitalized interest and other expenses	206	212	239
Total E&P capital investments	$ 1,231	$ 1,248	$ 623
E&P Capital Investments by Area			
Northeast Appalachia	$ 422	$ 489	$ 204
Southwest Appalachia	691	547	288
Fayetteville Shale (1)	33	114	86
Other (2)	85	98	45
Total E&P capital investments	$ 1,231	$ 1,248	$ 623

(1) The Fayetteville Shale E&P assets and associated reserves were divested on December 3, 2018.

(2) Includes $60 million and $37 million for the years ended December 31, 2018 and 2017 related to our water infrastructure project.

- The decrease in 2018 E&P capital investing, as compared to 2017, resulted from our commitment to invest within our cash flows from operations, which are heavily dependent on commodity prices.
- The significant increase in 2017 E&P capital investing, as compared to 2016, resulted from the resumption of activity following our decision to suspend drilling activity in the first half of 2016 due to an unfavorable commodity price environment. We began increasing activity in the second half of 2016 as forward pricing improved.
- In 2018, we drilled 106 wells (99 of which were spud in 2018), completed 119 wells, placed 138 wells to sales and had 51 wells in progress at year-end.
- Of the 51 wells in progress at year-end, 25 and 26 were located in Northeast Appalachia and Southwest Appalachia, respectively.

We refer you to “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Investing” within Item 7 of Part II of this Annual Report for additional discussion of the factors that could impact our planned capital investments in 2019.

Sales, Delivery Commitments and Customers

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

	For the years ended December 31, 2018	2017	2016
Average net daily production *(MMcfe/day)*	2,591	2,456	2,391
Production:			
Natural gas *(Bcf)*	807	797	788
Oil *(MBbls)*	3,407	2,327	2,192
NGLs *(MBbls)*	19,706	14,245	12,372
Total production *(Bcfe)*	946	897	875

- The increase in production in 2018 resulted primarily from a 64 Bcf increase in net production from our Northeast Appalachia properties and a 60 Bcfe increase in net production from our Southwest Appalachia properties, partially offset by a decrease of 73 Bcf from our Fayetteville Shale properties which were divested on December 3, 2018.
- The increase in production in 2017 resulted primarily from a 45 Bcf increase in net production from our Northeast Appalachia properties and a 35 Bcfe increase in net production from our Southwest Appalachia properties, partially offset by a 59 Bcf decrease in net production from our Fayetteville Shale properties.

	For the years ended December 31,		
	2018	2017	2016
Natural Gas Price:			
NYMEX Henry Hub Price *($/MMBtu)* [(1)]	**$ 3.09**	$ 3.11	$ 2.46
Discount to NYMEX [(2)]	**(0.64)**	(0.88)	(0.87)
Average realized gas price per Mcf, excluding derivatives	**$ 2.45**	$ 2.23	$ 1.59
Gain (loss) on settled financial basis derivatives *($/Mcf)*	**(0.04)**	(0.01)	0.03
Gain (loss) on settled commodity derivatives *($/Mcf)*	**(0.06)**	(0.03)	0.02
Average realized gas price per Mcf, including derivatives	**$ 2.35**	$ 2.19	$ 1.64
Oil Price:			
WTI oil price *($/Bbl)*	**$ 64.77**	$ 50.96	$ 43.32
Discount to WTI	**(7.98)**	(7.84)	(12.12)
Average oil price per Bbl, excluding derivatives	**$ 56.79**	$ 43.12	$ 31.20
Loss on settled derivatives *($/Bbl)*	**(0.72)**	–	–
Average oil price per Bbl, including derivatives	**$ 56.07**	$ 43.12	$ 31.20
NGL Price:			
Average net realized NGL price per Bbl, excluding derivatives	**$ 17.91**	$ 14.46	$ 7.46
Gain (loss) on settled derivatives *($/Bbl)*	**(0.68)**	0.02	–
Average net realized NGL price per Bbl, including derivatives	**$ 17.23**	$ 14.48	$ 7.46
Percentage of WTI, excluding derivatives	**28%**	28%	17%
Total Weighted Average Realized Price:			
Excluding derivatives *($/Mcfe)*	**$ 2.66**	$ 2.32	$ 1.62
Including derivatives *($/Mcfe)*	**$ 2.57**	$ 2.29	$ 1.66

(1) Based on last day settlement prices from monthly futures contracts.

(2) This discount includes a basis differential, a heating content adjustment, physical basis sales, third-party transportation charges and fuel charges, and excludes financial basis hedges.

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

As of December 31, 2018, we had the following commodity price derivatives in place on our targeted future production:

	For the years ended December 31,		
	2019	2020	2021
Natural gas *(Bcf)*	443	108	37
Oil *(MBbls)*	675	732	–
Ethane *(MBbls)*	3,687	732	–
Propane *(MBbls)*	1,689	–	–

As of February 26, 2019, we had the following commodity price derivatives in place on our targeted future production:

	For the years ended December 31,		
	2019	2020	2021
Natural gas *(Bcf)*	376	126	37
Oil *(MBbls)*	566	732	–
Ethane *(MBbls)*	3,091	732	–
Propane *(MBbls)*	1,935	366	–

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 Risk,” for further information regarding our derivatives and risk management as of December 31, 2018.

During 2018, the average price we received for our natural gas production, excluding the impact of derivatives, was approximately $0.64 per Mcf lower than average New York Mercantile Exchange, or NYMEX, prices. Differences between NYMEX and price realized (basis differentials) are due primarily to locational differences and transportation cost.

As of December 31, 2018, we have entered into physical sales arrangements to protect the basis on approximately 110 Bcf and 45 Bcf of our 2019 and 2020 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately ($0.16) per MMBtu and ($0.23) per MMBtu for 2019 and 2020, respectively.

We have also entered into basis swaps for approximately 107 Bcf and 59 Bcf of our 2019 and 2020 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately ($0.29) per MMBtu and ($0.44) per MMBtu for 2019 and 2020, respectively, as of December 31, 2018.

We refer you to Note 5 to the consolidated financial statements included in this Annual Report for additional discussion about our derivatives and risk management activities.

Delivery Commitments. As of December 31, 2018, we had natural gas delivery commitments of 269 Bcf in 2019 and 89 Bcf in 2020 under existing agreements. These amounts are well below our expected 2019 natural gas production from Northeast Appalachia and Southwest Appalachia and expected 2020 production from our available reserves, which are not subject to any priorities or curtailments that may affect quantities delivered to our customers or any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond our control that may affect our ability to meet our contractual obligations other than those discussed in Item 1A "Risk Factors" of Part I of this Annual Report. We expect to be able to fulfill all of our short-term and long-term contractual obligations to provide natural gas from our own production of available reserves; however, if we are unable to do so, we may have to purchase natural gas at market to fulfill our obligations.

Customers. Our E&P production is marketed primarily by our Midstream segment. Our customers include major energy companies, utilities and industrial purchasers of natural gas. For the years ended December 31, 2018 and 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.4% and 10.3%, respectively, of total natural gas, oil and NGL sales. During the year ended December 31, 2016, no single third-party purchaser accounted for 10% or more of our consolidated revenues. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production.

Competition

All phases of the natural gas and oil industry are highly competitive. We compete in the acquisition and disposition of properties, the search for and development of reserves, the production and marketing of natural gas, oil and NGLs, and the securing of labor, services and equipment required to conduct our operations. Our competitors include major oil and natural gas companies, other independent oil and natural gas companies and individual producers. 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. Likewise, there are substitutes for the commodities we produce, such as other fuels for power generation, heating and transportation, and those markets in effect compete with us.

We cannot predict whether and to what extent any regulatory changes initiated by the Federal Energy Regulatory Commission, or the FERC, or any other 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, oil and NGL resources and transporting and selling production historically have been heavily regulated. For example, state governments regulate the location of wells and establish the minimum size for spacing units. Permits typically are required before drilling. State and local government zoning and land use regulations may also limit the locations for drilling and production. Similar regulations can also affect the location, construction and operation of gathering and other pipelines needed to transport production to market. In addition, various suppliers of goods and services may require licensing.

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

Producing and transporting natural gas, oil and NGLs 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

We engage in marketing and, prior to the Fayetteville Shale sale, natural gas gathering activities which primarily support our E&P operations. We generate revenue through the marketing of natural gas, oil and NGLs and, historically, from gathering fees associated with in-field gathering activities. The Fayetteville Shale sale, which closed on December 3, 2018, included all gathering assets associated with our previous operations in Arkansas, which comprised the vast majority of our gathering business.

	For the years ended December 31,		
	2018	2017	2016
Marketing revenues *(in millions)*	**$ 3,497**	$ 2,867	$ 2,191
Gathering revenues *(in millions)*	**248**	331	378
Total operating revenues *(in millions)*	**$ 3,745**	$ 3,198	$ 2,569
Operating income *(in millions)*	**$ 4**	$ 183	$ 209
Cash flows from operations *(in millions)*	**$ 70**	$ 208	$ 222
Capital investments – gathering *(in millions)*	**$ 9**	$ 32	$ 21
Natural gas gathered from the Fayetteville Shale *(Bcf)*			
Operated wells *(Bcf)*	**355**	463	558
Third-party operated wells *(Bcf)*	**26**	35	42
Total volumes gathered in the Fayetteville Shale *(Bcf)*	**381**	498	600
Volumes marketed *(Bcfe)*	**1,163**	1,067	1,062
Percent natural gas marketed from affiliated E&P operations	**93%**	96%	93%
Percent oil and NGLs marketed from affiliated E&P operations	**69%**	63%	65%

- Operating income for the year ended December 31, 2018 included $155 million of impairments, primarily related to our gathering assets divested as part of the Fayetteville Shale sale along with certain other non-core gathering assets, and $2 million of restructuring charges. Excluding these charges, operating income from our Midstream segment decreased $22 million in 2018 compared to 2017, primarily due to an $83 million decrease in gas gathering revenues and a $1 million decrease in marketing margin, partially offset by a $33 million decrease in operating costs and expenses and a $29 million increase in gain on sale of assets, net.
- Operating income decreased $26 million in 2017 compared to 2016, primarily due to a $47 million decrease in gas gathering revenues related to a decrease in Fayetteville Shale gathered volumes, and a $3 million decrease in marketing margin, partially offset by an $18 million decrease in operating costs and expenses, primarily related to decreased compression rental and maintenance activities, and a $6 million gain on sale of certain compressor equipment.
- Revenues increased in 2018, compared to 2017, as the effect of an increase in the price received for volumes marketed was only partially offset by a decrease in volumes gathered.
- Revenues increased in 2017, compared to 2016, primarily due to an increase in the price received for volumes marketed which was only partially offset by a decrease in volumes gathered.

- Cash flow from operations generated by our Midstream segment decreased in 2018, compared to 2017, primarily due to an $83 million decrease in gas gathering revenues, partially offset by a $12 million decrease in cash operating costs and expenses, a $64 million decrease related to timing differences of payables and receivables between the respective periods and a $3 million decrease in Other Income (Loss), Net.
- The decrease in cash flow from operations in 2017, compared to 2016, was primarily due to a $26 million decrease in operating income, partially offset by a $12 million increase primarily related to timing differences of payables and receivables between the respective periods.

Gas Gathering

On December 3, 2018, we sold our gathering operations in Arkansas as part of the Fayetteville Shale sale. Our remaining interests in gathering systems are not expected to generate material revenues.

Marketing

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

Northeast Appalachia. Our transportation portfolio in Northeast Appalachia is highly-diversified and allows us to access premium city-gate markets as well as to deliver natural gas from the Appalachia area to the southeast United States. The capacity agreements contain multiple extension and reduction options that allow us to right-size our transportation portfolio as needed for our production or to capture future market opportunities. The table below details our firm transportation, firm sales and total takeaway capacity over the next three years as of February 26, 2019:

	For the remaining year ended December 31,		
(MMBtu/d)	2019	2020	2021
Firm transportation	1,305,000	1,325,000	1,316,000
Firm sales	156,000	54,000	35,000
Total firm takeaway – Northeast Appalachia	1,461,000	1,379,000	1,351,000

Southwest Appalachia. Our transportation portfolio for all products in Southwest Appalachia allows us to capitalize on strengthening markets and provides a path for production growth. Agreements with ET Rover Pipeline LLC and Columbia Pipeline Group, Inc.'s Mountaineer Xpress and Gulf Xpress pipelines will allow us to access high-demand markets along the Gulf Coast while also capturing materially improving in-basin pricing. In addition to our natural gas transportation, we have ethane take-away capacity that provides direct access to Mont Belvieu pricing. New ethane cracker demand and export capacity is expected to further strengthen ethane pricing. The table below details our natural gas firm transportation, firm sales and total takeaway capacity over the next three years as of February 26, 2019:

	For the remaining year ended December 31,		
(MMBtu/d)	2019	2020	2021
Firm transportation	694,000	777,000	868,000
Firm sales	8,000	8,000	45,000
Total firm takeaway – Southwest Appalachia	702,000	785,000	913,000

Demand Charges

As of December 31, 2018, our obligations for demand and similar charges under the firm transportation agreements and gathering agreements totaled approximately $8.8 billion, $3.1 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 $463 million of that amount. As part of the Fayetteville Shale sale, we retained certain contractual commitments related to firm transportation, with the buyer obligated to pay the transportation provider directly for these charges. As of December 31, 2018, approximately $221 million of these contractual commitments remain of which we will reimburse the buyer for certain of these potential obligations up to approximately $102 million through 2020 depending on the buyer's actual use. We have recorded an $88 million liability which is the present value of the estimated future payments. The buyer will also assume future asset retirement obligations related to the operations sold.

Subsequent to December 31, 2018, we agreed to purchase firm transportation with pipelines in the Appalachian Basin starting in 2021 and running through 2032 totaling $357 million in total contractual commitments of which the seller has agreed to reimburse us for $133 million.

We refer you to Note 9 – "Commitments and Contingencies" to the consolidated financial statements included in this Annual Report for further details on our demand charges and the risk factor "We have entered into long-term gathering and transportation contracts and have made significant investments in oilfield services 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 customers.

Customers

Our marketing customers include major energy companies, utilities and industrial purchasers of natural gas. For the years ended December 31, 2018 and 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.4% and 10.3%, respectively, of total natural gas, oil and NGL sales. During the year ended December 31, 2016, no single third-party purchaser accounted for 10% or more of our consolidated revenues. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production.

Regulation

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

State and local permitting, zoning and land use regulations can affect the location, construction and operation of gathering and other pipelines needed to transport production to market, and the lack of new pipeline capacity can limit our ability to reach relevant markets for the sale of the commodities we produce.

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

Other

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

Environmental Regulation

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

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

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

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

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

The Oil Pollution Act, as amended, or OPA, and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in regulated waters. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. Although liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. Oil accounted for 2% of our total production in 2018 and 2017 and 1% of our total production in 2016, although we expect this percentage to increase as we continue to develop our Southwest Appalachia assets.

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

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

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

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

In the past several 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. In September 2018, the EPA issued proposed revisions to those regulations, which, if finalized, would reduce certain obligations thereunder. The EPA also finalized pretreatment standards that would prohibit the indirect discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned treatment works. Based on our current operations and practices, management believes such newly promulgated rules will not have a material adverse impact on our financial position, results of operations or cash flows but these matters are subject to inherent uncertainties and management's view may change in the future.

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

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

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

In addition, concerns have been raised about the potential for seismic activity to occur from the use of underground injection control wells, a predominant method for disposing of waste water from oil and gas activities. 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 utilize third parties to dispose of waste water associated with our operations. These third parties may operate injection wells and may be subject to regulatory restrictions relating to seismicity.

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

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

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

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

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

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

Employees

As of December 31, 2018, we had 960 total employees, a decrease of 39% compared to year-end 2017, following workforce reductions and the Fayetteville Shale sale. None of our employees were covered by a collective bargaining agreement at year-end 2018. We believe that our relationships with our employees are good.

Executive Officers of the Registrant

The following table shows certain information as of February 26, 2019 about our executive officers, as defined in Rule 3b-7 of the Securities Exchange Act of 1934:

Name	Age	Officer Position
William J. Way	59	President and Chief Executive Officer
Julian M. Bott	56	Executive Vice President and Chief Financial Officer
Clayton A. Carrell	53	Executive Vice President and Chief Operating Officer
J. David Cecil	52	Executive Vice President Corporate Development
Jennifer E. Stewart	55	Senior Vice President – Government & Regulatory Affairs
Jennifer N. McCauley	55	Senior Vice President – Administration
John C. Ale	64	Senior Vice President, General Counsel and Secretary
Jason Kurtz	48	Vice President – Marketing and Transportation

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

Mr. Bott was appointed Executive Vice President and Chief Financial Officer in February 2018. Prior to that, he was Executive Vice President and Chief Financial Officer of SandRidge Energy, Inc. since 2015.

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

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

Ms. Stewart was appointed Senior Vice President – Government & Regulatory Affairs in March 2018. Prior to that, she served as Chief Financial Officer – Interim and Senior Vice President, Tax and Treasury. Ms. Stewart joined the Company in 2010 as Vice President, Tax.

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

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

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

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

GLOSSARY OF CERTAIN INDUSTRY TERMS

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

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

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

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

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

"Bcf" One billion cubic feet of natural gas.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"Mcf" One thousand cubic feet of natural gas.

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

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

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

"MMcf" One million cubic feet of natural gas.

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

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

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

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

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

"NGLs" Natural gas liquids (includes ethane, propane, butane, isobutane, pentane and pentanes plus).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ITEM 1A. RISK FACTORS

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

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

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

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

For example, in 2017 and 2018, the NYMEX settlement price for natural gas ranged from a low of $2.63 per MMBtu in March 2017 to a high of $4.72 per MMBtu in December 2018, and during this period our production was 89% and 85% natural gas, respectively. NGLs represent a growing part of our business, and in the same period prices for ethane and propane, our two principal NGL products, ranged from $1.81 per Bbl in December 2017 to $14.64 per Bbl in September 2018 and $16.91 per Bbl in June 2017 to $36.35 per Bbl in December 2017, respectively. Although we hedge a large portion of our production against changing prices, derivatives do not protect all our future volumes, may result in our forgoing profit opportunities if markets rise and, for NGLs, are not always available for substantial periods into the future. In 2018, we paid $94 million, net of amounts we received, in settlement of hedging arrangements.

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

As of December 31, 2018, we had $2.3 billion of debt outstanding, consisting principally of senior notes maturing in various increments from 2020 to 2027, and no borrowings under our revolving credit facility. At current commodity price levels, our net cash flow from operations is substantially higher than our interest obligations under this debt, but significant drops in realized prices could affect our ability to pay our current obligations or refinance our debt as it becomes due.

Moreover, general industry conditions may make it difficult or costly to refinance increments of this debt as it matures. Although our indentures do not contain significant covenants restricting our operations and other activities, our bank credit agreements contain financial covenants with which we must comply. We refer you to the risk factor "Our current and future levels of indebtedness may adversely affect our results and limit our growth." Our inability to pay our current obligations or refinance our debt as it becomes due could have a material and adverse effect on our company. The drop in prices since 2014 has reduced our revenues, profits and cash flow, caused us to record significant asset impairments and led us to reduce both our level of capital investing and our workforce, which has caused us to incur significant expenses relating to employee terminations. Further price decreases could have similar consequences. Similarly, a rise in prices to levels experienced before 2015 could significantly increase our revenues, profits and cash flow, which could be used to expand capital investments.

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

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

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

Production levels from existing wells decline over time, and drilling new wells requires an inventory of leases and other rights with reserves that have not yet been drilled. Our future success depends largely upon our ability to find, develop or acquire additional natural gas, oil and NGL reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, acquisition or exploration activities, our proved reserves and production will decline over time. Identifying and exploiting new reserves requires significant capital investment and successful drilling operations. Thus, our future natural gas, oil and NGL reserves and production, and therefore our revenues and profits, are highly dependent on our level of capital investments, our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

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

The marketability of our natural gas, oil and NGL production depends in large part on the operation, availability, proximity, capacity and expansion of transportation systems and facilities owned by third parties. For example, we can provide no assurance that sufficient transportation capacity will exist for expected production from the Appalachian Basin or that we will be able to obtain sufficient transportation capacity on economic terms. During the past three years, several planned pipelines intended to service production in the Northeast United States 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.

A 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 review for a downgrade, could impact our ability to access debt markets in the future to refinance existing debt or obtain additional funds, 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 of the likelihood we will be able to repay our debt at the time the rating is issued. An explanation of the significance of each rating may be obtained from the applicable rating agency. As of February 26, 2019, our long-term issuer ratings were Ba2 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 $112 million of letters of credit outstanding at December 31, 2018. The amount of additional financial assurance would depend on the severity of the downgrade from the credit rating agencies, and a downgrade could result in a decrease in our liquidity.

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

We necessarily must consider future price and cost environments when deciding how much capital we are likely to have available from net cash flow and how best to allocate it. Our current philosophy is to generally operate within cash flow from operations net of changes in working capital and to invest capital only in projects 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.

Approximately 13,123 and 43,092 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 or be judged to be the best use of our capital. To the extent we do not drill the wells, our rights to acreage can be lost.

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

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

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

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

We rely on third parties to transport our production to markets. Their operations, and thus our ability to reach markets, 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, 2018, we had long-term indebtedness of $2.3 billion. The terms of the indentures governing our outstanding senior notes, our credit facilities, and the lease agreements relating to our drilling rigs, other equipment and headquarters building, which we collectively refer to as our "financing agreements," impose restrictions on our ability and, in some cases, the ability of our subsidiaries to take a number of actions that we may otherwise desire to take, which may include, without limitation, one or more of the following:

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

The revolving credit facility we entered into in April 2018 (our "revolving credit facility") contains customary representations, warranties and covenants including, among others, the following covenants:

- a prohibition against incurring debt, subject to permitted exceptions;
- a restriction on creating liens on assets, subject to permitted exceptions;
- restrictions on mergers and asset dispositions;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business; and
- maintenance of the following financial covenants, commencing with the fiscal quarter ended June 30, 2018:
    1. Minimum current ratio of no less than 1.00 to 1.00, whereby current ratio is defined as the Company's consolidated current assets (including unused commitments under the credit agreement, but excluding non-cash derivative assets) to consolidated current liabilities (excluding non-cash derivative obligations and current maturities of long-term debt).
    2. Maximum total net leverage ratio of no less than (i) with respect to each fiscal quarter ending during the period from June 30, 2018 through March 31, 2019, 4.50 to 1.00, (ii) with respect to each fiscal quarter ending during the period from June 30, 2019 through March 31, 2020, 4.25 to 1.00, and (iii) with respect to each fiscal quarter ending on or after June 30, 2020, 4.00 to 1.00. Total net leverage ratio is defined as total debt less cash on hand (up to the lesser of 10% of credit limit or $150 million) divided by consolidated EBITDAX for the last four consecutive quarters. EBITDAX, as defined in our revolving credit facility, excludes the effects of interest expense, depreciation, depletion and amortization, income tax, 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.

In the fourth quarter of 2018, we entered into hedges that, when added to then-existing hedges including hedges put in place as part of the Fayetteville Shale sale that the buyer was obligated to assume at closing of that sale, exceeded a cap on hedges for the month of December 2018 under a covenant under our credit agreement. In conjunction with the closing, the buyer paid for the settlement of the December 2018 hedges it was to assume. The lenders have subsequently waived all matters associated with this default. Otherwise, as of December 31, 2018, we were in compliance with all of the remaining covenants of our revolving credit facility in all material respects. Although we do not anticipate any future violations of our financial covenants, our ability to comply with these covenants depends in part on the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas, oil and NGLs.

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.

Any significant reduction in our borrowing base under our revolving credit facility as a result of periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our revolving credit facility if required as a result of a borrowing base redetermination.

The amount we may borrow under our revolving credit facility is capped at the lower of our commitment and a "borrowing base" determined from time to time by the lenders based on our reserves, market conditions and other factors. As of December 31, 2018, the borrowing base was $2.1 billion, which is above the total current commitments of $2.0 billion. The borrowing base is subject to scheduled semiannual and other elective collateral borrowing base redeterminations based on our natural gas, oil and NGL reserves and other factors. As of December 31, 2018, we had no outstanding borrowings under our revolving credit facility, though we may elect to borrow under that facility in the future. As of December 31, 2018, we had $112 million of letters of credit issued under the credit facility and unused borrowing capacity was approximately $1.9 billion. Any significant reduction in our borrowing base as a result of borrowing base redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our revolving credit facility were to exceed the borrowing base as a result of any such redetermination, we would be required to repay the excess with short notice. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

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.

Failure to comply with the covenants and other restrictions could lead to an event of default and the acceleration of our obligations under our senior notes, credit facilities or other financing agreements, and in the case of the lease agreements for drilling rigs, compressors and pressure pumping equipment, loss of use of the equipment. In particular, the occurrence of risks identified elsewhere in this section, such as declines in commodity prices, increases in basis differentials and inability to access markets, could reduce our profits and thus the cash we have to fulfill our financial obligations. 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 entered into long-term gathering and transportation contracts and have made significant investments in oilfield service businesses, including our drilling rigs, water infrastructure and pressure pumping equipment, to lower costs and secure inputs for our operations and transportation for our production. If our development 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.

We have entered into gathering agreements in producing areas and multiple long-term firm transportation agreements relating to natural gas volumes from all our producing areas. As of December 31, 2018, our aggregate demand charge commitments under these firm transportation agreements and gathering agreements were approximately $8.8 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 investments to meet certain of our field services' needs, including establishing our own drilling rig operation, water transportation system in Southwest Appalachia and pressure pumping capability. If our level of operations is reduced for a long period, we may not be able to recover these investments. Further, our presence in these service and supply sectors, including competing with them for qualified personnel and supplies, may have an adverse effect on our relationships with our existing third-party service and resource providers or our ability to secure these services and resources from other providers.

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

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 seismic activity to occur from the use of underground injection control wells, a predominant method for disposing of waste water from oil and gas activities. 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 utilize third parties to dispose of waste water associated with our operations. These third parties may operate injection wells and may be subject to regulatory restrictions relating to seismicity.

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 the Appalachian Basin, making us vulnerable to risks associated with operating in limited geographic areas.

Our producing properties currently are geographically concentrated in the Appalachian Basin in Pennsylvania and West Virginia. At December 31, 2018, nearly 100% of our total estimated proved reserves were attributable to properties located in the Appalachian Basin. As a result of this concentration in one primary region, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, state politics, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or interruption of the processing or transportation of natural gas, oil or NGLs.

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

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

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

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

The EPA also has adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore natural gas and oil production sources in the United States on an annual basis, which include certain of our operations. In May 2016, the EPA finalized additional regulations to control methane and volatile organic compound emissions from certain oil and gas equipment and operations. However, in September 2018, the EPA issued proposed revisions to those regulations, which, if finalized, would reduce certain obligations thereunder.

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

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

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

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

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

Our business may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are reduced energy demand and lower commodity prices, increased difficulty in collecting amounts owed to us by our customers, reduced access to credit markets and the risks related to the discontinuation of LIBOR and other reference rates, including increased expenses and litigation and the effectiveness of interest rate hedge strategies. 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.

Any changes in U.S. trade policy could trigger retaliatory actions by affected countries, resulting in "trade wars," in increased costs for materials necessary for our industry along with other goods imported into the United States, which may reduce customer demand for these products if the parties having to pay those tariffs increase their prices, or in trading partners limiting their trade with the United States. If these consequences are realized, the volume of economic activity in the United States, including growth in sectors that utilize our products, may be materially reduced along with a reduction in the potential export of our products. Such a reduction may materially and adversely affect commodity prices, our sales and our business.

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

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

Our proved natural gas, oil and NGL reserves are estimates that include uncertainties. Any material changes to these uncertainties 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 historic 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 preceding 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 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. To the extent we cap or lock prices at specific levels, we would also forgo the ability to realize the higher revenues that would be realized should prices increase.

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

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

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

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

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

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

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

Further regulations relating to and interpretations of the recently enacted Tax Cuts and Jobs Act may have a material impact on our financial condition and results of operations.

On December 22, 2017, President Trump signed into law H.R. 1 (commonly referred to as the "Tax Cuts and Jobs Act," or the "Tax Reform Act"), a comprehensive tax reform bill that significantly reforms the Internal Revenue Code of 1986, as amended. The Tax Reform Act, among other things, contains significant changes to corporate taxation, including a permanent reduction of the corporate income tax rate, a partial limitation on the deductibility of business interest expense, limitation of the deduction for certain net operating losses to 80% of current year taxable income for tax years 2018 and beyond, an indefinite net operating loss carryforward, immediate deductions for certain new investments instead of deductions for depreciation expense over time and the modification or repeal of many business deductions and credits. The Treasury Department and the Internal Revenue Service continue to release regulations relating to and interpretive guidance of the legislation contained in the Tax Reform Act. Any significant variance of our current interpretation of such legislation from any future regulations or interpretive guidance could result in a change to the presentation of our financial condition and results of operations and could negatively affect our business.

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

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

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

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

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

Deferred tax assets, including net operating loss carryforwards, represent future savings of taxes that would otherwise be paid in cash. At December 31, 2018, we had substantial amounts of net operating loss carryforwards for U.S. federal and state income tax purposes. Limitations may exist upon use of these carryforwards in the event that a change in control of the Company occurs. Additionally, due to the Tax Reform Act's permanent reduction of the corporate income tax rate, we were required to write down our deferred tax assets (including our net operating loss carryforwards), and there may be other material adverse effects on our deferred tax assets resulting from the Tax Reform Act that we have not yet identified.

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. At December 31, 2018, we recorded a valuation allowance against our entire deferred tax asset, including the portion related to the remaining net operating loss carryforwards. This allowance was recorded primarily as a result of cumulative book losses experienced over the three-year period ending December 31, 2018. 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 released 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 release 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 as well as processing of revenues and payments. 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 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 companies with which we deal, could disrupt our business and negatively impact our operations in a variety of ways, including:

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

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

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

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

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

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

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about emissions, hydraulic fracturing, seismicity, oil spills and explosions of 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.

Judicial decisions can affect our rights and obligations.

Our ability to develop gas, oil and NGLs depends on the leases and other mineral rights we acquire and the rights of owners of nearby properties. We operate in areas where judicial decisions have not yet definitively interpreted various contractual provisions or addressed relevant aspects of property rights, nuisance and other matters that could be the source of claims against us as a developer or operator of properties. Although we plan our activities according to our expectations of these unresolved areas, based on decisions on similar issues in these jurisdictions and decisions from courts in other states that have addressed them, courts could resolve issues in ways that increase our liabilities or otherwise restrict or add costs to our operations.

Common stockholders will be diluted if additional shares are issued.

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The summary of our oil and natural gas reserves as of fiscal year-end 2018 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed "2018 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 Investing." 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, 2018

	Undeveloped		Developed		**Total**	
	Gross	Net	Gross	Net	**Gross**	**Net**
Northeast Appalachia	94,067	73,174	115,483	110,850	**209,550**	**184,024**
Southwest Appalachia	402,218	220,331	110,227	77,114	**512,445**	**297,445**
Other:						
US – Other Exploration	349,860	135,621	5,034	2,263	**354,894**	**137,884**
US – Sand Wash Basin	24,455	17,538	14,977	10,698	**39,432**	**28,236**
Canada – New Brunswick [1]	2,518,519	2,518,519	–	–	**2,518,519**	**2,518,519**
	3,389,119	2,965,183	245,721	200,925	**3,634,840**	**3,166,108**

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

Lease Expirations

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

	For the years ended December 31,		
Net acreage expiring:	2019	2020	2021
Northeast Appalachia	7,429	3,857	1,837
Southwest Appalachia [1]	21,761	14,630	6,701
Other:			
US – Other Exploration	87,498	30,686	9,032
US – Sand Wash Basin	5,761	989	7
Canada – New Brunswick [2]	–	–	2,518,519

(1) Of this acreage, 9,410 net acres in 2019, 5,300 net acres in 2020 and 2,647 net acres in 2021 can be extended for an average of 4.8 years.

(2) Exploration licenses were extended through 2021 but have been subject to a moratorium since 2015.

Producing wells as of December 31, 2018

	Natural Gas		Oil		**Total**		Gross Wells
	Gross	Net	Gross	Net	**Gross**	**Net**	Operated
Northeast Appalachia	666	592	–	–	**666**	**592**	600
Southwest Appalachia	466	333	–	–	**466**	**333**	437
Other	6	3	11	11	**17**	**14**	17
	1,138	928	11	11	**1,149**	**939**	1,054

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
2018						
Northeast Appalachia	**–**	**–**	**–**	**–**	**–**	**–**
Southwest Appalachia	**–**	**–**	**–**	**–**	**–**	**–**
Fayetteville Shale (1)	**–**	**–**	**–**	**–**	**–**	**–**
Other	**–**	**–**	**–**	**–**	**–**	**–**
Total	**–**	**–**	**–**	**–**	**–**	**–**
2017						
Northeast Appalachia	–	–	–	–	–	–
Southwest Appalachia	–	–	–	–	–	–
Fayetteville Shale (1)	–	–	–	–	–	–
Other	1.0	1.0	–	–	1.0	1.0
Total	1.0	1.0	–	–	1.0	1.0
2016						
Northeast Appalachia	1.0	1.0	–	–	1.0	1.0
Southwest Appalachia	–	–	–	–	–	–
Fayetteville Shale (1)	–	–	–	–	–	–
Other	–	–	–	–	–	–
Total	1.0	1.0	–	–	1.0	1.0

(1) The Fayetteville Shale E&P assets were sold on December 3, 2018.

	Development					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2018						
Northeast Appalachia	**60.0**	**59.5**	**–**	**–**	**60.0**	**59.5**
Southwest Appalachia	**76.0**	**59.3**	**–**	**–**	**76.0**	**59.3**
Fayetteville Shale (1)	**2.0**	**1.8**	**–**	**–**	**2.0**	**1.8**
Total	**138.0**	**120.6**	**–**	**–**	**138.0**	**120.6**
2017						
Northeast Appalachia	83.0	80.8	–	–	83.0	80.8
Southwest Appalachia	57.0	43.6	–	–	57.0	43.6
Fayetteville Shale (1)	25.0	24.1	–	–	25.0	24.1
Total	165.0	148.5	–	–	165.0	148.5
2016						
Northeast Appalachia	23.0	22.9	–	–	23.0	22.9
Southwest Appalachia	18.0	13.4	–	–	18.0	13.4
Fayetteville Shale (1)	43.0	35.2	–	–	43.0	35.2
Total	84.0	71.5	–	–	84.0	71.5

(1) The Fayetteville Shale E&P assets were sold on December 3, 2018.

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, 2018

	Gross	Net
Drilling:		
Northeast Appalachia	24.0	23.0
Southwest Appalachia	26.0	20.5
Total	**50.0**	**43.5**
Completing:		
Northeast Appalachia	1.0	1.0
Southwest Appalachia	–	–
Total	**1.0**	**1.0**
Drilling & Completing:		
Northeast Appalachia	25.0	24.0
Southwest Appalachia	26.0	20.5
Total	**51.0**	**44.5**

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,		
	2018	2017	2016
Natural Gas			
Production *(Bcf)*:			
Northeast Appalachia	**459**	395	350
Southwest Appalachia	**105**	85	62
Fayetteville Shale (1)	**243**	316	375
Other	**–**	1	1
Total	**807**	797	788
Average realized gas price per Mcf, excluding derivatives:			
Northeast Appalachia	**$ 2.54**	$ 2.11	$ 1.34
Southwest Appalachia	**$ 2.58**	$ 2.28	$ 1.71
Fayetteville Shale (1)	**$ 2.21**	$ 2.35	$ 1.80
Total	**$ 2.45**	$ 2.23	$ 1.59
Average realized gas price per Mcf, including derivatives	**$ 2.35**	$ 2.19	$ 1.64
Oil			
Production *(MBbls)*:			
Southwest Appalachia	**3,355**	2,228	2,041
Other	**52**	99	151
Total	**3,407**	2,327	2,192
Average realized oil price per Bbl, excluding derivatives:			
Southwest Appalachia	**$ 56.71**	$ 42.93	$ 30.59
Other	**$ 62.01**	$ 47.38	$ 39.44
Total	**$ 56.79**	$ 43.12	$ 31.20
Average realized oil price per Bbl, including derivatives	**$ 56.07**	$ 43.12	$ 31.20
NGL			
Production *(MBbls)*:			
Southwest Appalachia	**19,679**	14,193	12,317
Other	**27**	52	55
Total	**19,706**	14,245	12,372
Average realized NGL price per Bbl, excluding derivatives:			
Southwest Appalachia	**$ 17.89**	$ 14.42	$ 7.41
Other	**$ 28.12**	$ 26.38	$ 17.33
Total	**$ 17.91**	$ 14.46	$ 7.46
Average realized NGL price per Bbl, including derivatives	**$ 17.23**	$ 14.48	$ 7.46
Total Production *(Bcfe)*			
Northeast Appalachia	**459**	395	350
Southwest Appalachia (2)	**243**	183	148
Fayetteville Shale (1)	**243**	316	375
Other	**1**	3	2
Total	**946**	897	875
Average Production Cost			
Cost per Mcfe, excluding ad valorem and severance taxes:			
Northeast Appalachia	**$ 0.81**	$ 0.75	$ 0.76
Southwest Appalachia	**$ 1.08**	$ 1.07	$ 1.05
Fayetteville Shale (1)	**$ 0.98**	$ 0.97	$ 0.89
Total	**$ 0.93**	$ 0.90	$ 0.87

(1) The Fayetteville Shale E&P assets and associated reserves were sold December 3, 2018.

(2) Approximately 240 Bcfe, 179 Bcfe and 148 Bcfe for the years ended December 31, 2018, 2017 and 2016, respectively, were produced from the Marcellus Shale formation.

During 2018, 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.

Title to Properties

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

ITEM 3. LEGAL PROCEEDINGS

We are subject to litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. It is not possible at this time to estimate the amount of any additional loss, or range of loss that is reasonably possible, but based on the nature of the claims, management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows, for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future. 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 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 9 – "Commitments and Contingencies" to the consolidated financial statements included in this Annual Report 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 26, 2019, the closing price of our common stock trading under the symbol "SWN" was $4.34 and we had 2,873 stockholders of record. We currently do not pay dividends on our common stock.

Issuer Purchases of Equity Securities

In 2018, we repurchased 39,061,269 of our outstanding common stock for approximately $180 million at an average price of $4.63 per share.

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, 2018:

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 2018	4,843,532	$ 5.10	4,840,000	$ 150,296,574
November 2018	10,000,295	$ 5.35	10,000,295	$ 96,813,332
December 2018	19,509,158	$ 3.96	19,391,963	$ 20,089,542
Total fourth-quarter 2018:	34,352,985	$ 4.53	34,232,258	

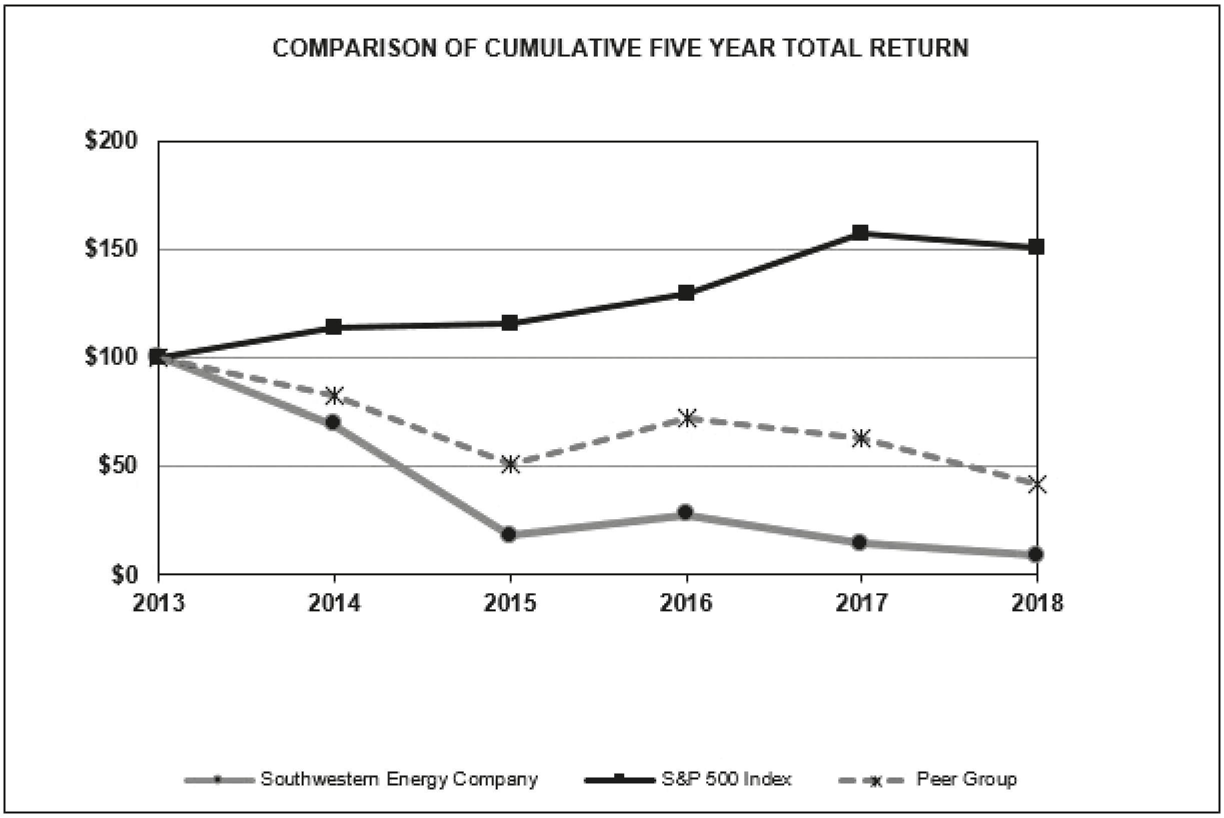
(1) Includes 120,727 shares retired by us to satisfy applicable tax withholding obligations due on employee stock plan share issuances. The remaining shares were repurchased through open-market transactions with a portion of the net proceeds from the Fayetteville Shale sale which closed on December 3, 2018.

Recent Sales of Unregistered Equity Securities

We did not sell any unregistered equity securities during 2018, 2017 or 2016. 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, 2018.

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, Antero Resources Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Company, Concho Resources, Inc., Continental Resources, Inc., Devon Energy Corporation, EQT Corporation, Gulfport Energy Corporation, Newfield Exploration Company, Noble Energy, Inc., PDC Energy, Inc., QEP Resources, Inc., Range Resources Corporation, SM Energy Company 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, 2013, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance:



	12/31/13	12/31/14	12/31/15	12/31/16	12/31/17	12/31/18
Southwestern Energy Company	$ 100	$ 69	$ 18	$ 28	$ 14	$ 9
S&P 500 Index	100	114	115	129	157	150
Peer Group	100	82	51	73	63	42

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, 2018. 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."

	2018	2017	2016	2015	2014
	(in millions except shares, per share, stockholder data and percentages)				
Financial Review					
Operating revenues:					
Exploration and production	$ 2,525	$ 2,086	$ 1,413	$ 2,074	$ 2,862
Midstream	3,745	3,198	2,569	3,119	4,358
Intersegment revenues	(2,408)	(2,081)	(1,546)	(2,060)	(3,182)
	3,862	3,203	2,436	3,133	4,038
Operating costs and expenses:					
Marketing purchases – midstream	1,229	976	864	852	980
Operating and general and administrative expenses	994	904	839	935	648
Restructuring charges	39	–	73	–	–
Depreciation, depletion and amortization	560	504	436	1,091	942
Impairments	171	–	2,321	6,950	–
Gain on sale of assets, net	(17)	(6)	–	(283)	–
Taxes, other than income taxes	89	94	93	110	95
	3,065	2,472	4,626	9,655	2,665
Operating income (loss)	797	731	(2,190)	(6,522)	1,373
Interest expense, net	124	135	88	56	59
Gain (loss) on derivatives	(118)	422	(339)	47	139
Loss on early extinguishment of debt	(17)	(70)	(51)	–	–
Other income (loss), net	–	5	(4)	(30)	(4)
Income (loss) before income taxes	538	953	(2,672)	(6,561)	1,449
Provision (benefit) for income taxes:					
Current	1	(22)	(7)	(2)	21
Deferred	–	(71)	(22)	(2,003)	504
	1	(93)	(29)	(2,005)	525
Net income (loss)	537	1,046	(2,643)	(4,556)	924
Mandatory convertible preferred stock dividend	–	108	108	106	–
Participating securities – mandatory convertible preferred stock	2	123	–	–	–
Net income (loss) attributable to common stock	$ 535	$ 815	$ (2,751)	$ (4,662)	$ 924
Net cash provided by operating activities	$ 1,223	$ 1,097	$ 498	$ 1,580	$ 2,335
Net cash provided by (used in) investing activities	$ 359	$ (1,252)	$ (162)	$ (1,638)	$ (7,288)
Net cash provided by (used in) financing activities	$ (2,297)	$ (352)	$ 1,072	$ 20	$ 4,983
Common Stock Statistics					
Earnings per share:					
Net income (loss) attributable to common stockholders – Basic	$ 0.93	$ 1.64	$ (6.32)	$ (12.25)	$ 2.63
Net income (loss) attributable to common stockholders – Diluted	$ 0.93	$ 1.63	$ (6.32)	$ (12.25)	$ 2.62
Book value per average diluted share	$ 4.10	$ 3.95	$ 2.11	$ 6.00	$ 13.23
Market price at year-end	$ 3.41	$ 5.58	$ 10.82	$ 7.11	$ 27.29
Number of stockholders of record at year-end	2,886	3,216	3,292	3,415	3,271
Average diluted shares outstanding	576,642,808	500,804,297	435,337,402	380,521,039	352,410,683

	2018	2017	2016	2015	2014
Capitalization *(in millions)*					
Total debt	$ 2,318	$ 4,391	$ 4,653	$ 4,705	$ 6,957
Total equity	2,362	1,979	917	2,282	4,662
Total capitalization	$ 4,680	$ 6,370	$ 5,570	$ 6,987	$ 11,619
Total assets	$ 5,797	$ 7,521	$ 7,076	$ 8,086	$ 14,915
Capitalization ratios:					
Debt	50%	69%	84%	67%	60%
Equity	50%	31%	16%	33%	40%
Capital Investments *(in millions)* (1)					
Exploration and production	$ 1,231	$ 1,248	$ 623	$ 2,258	$ 7,254
Midstream	9	32	21	167	144
Other	8	13	4	12	49
	$ 1,248	$ 1,293	$ 648	$ 2,437	$ 7,447
Exploration and Production					
Natural gas:					
Production *(Bcf)*	807	797	788	899	766
Average realized price per Mcf, including derivatives	$ 2.35	$ 2.19	$ 1.64	$ 2.37	$ 3.72
Average realized price per Mcf, excluding derivatives	$ 2.45	$ 2.23	$ 1.59	$ 1.91	$ 3.74
Oil:					
Production *(MBbls)*	3,407	2,327	2,192	2,265	235
Average realized price per barrel, including derivatives	$ 56.07	$ 43.12	$ 31.20	$ 33.25	$ 79.91
Average realized price per barrel, excluding derivatives	$ 56.79	$ 43.12	$ 31.20	$ 33.25	$ 79.91
NGL:					
Production *(MBbls)*	19,706	14,245	12,372	10,702	231
Average realized price per barrel, including derivatives	$ 17.23	$ 14.48	$ 7.46	$ 6.80	$ 15.72
Average realized price per barrel, excluding derivatives	$ 17.91	$ 14.46	$ 7.46	$ 6.80	$ 15.72
Total production *(Bcfe)*	946	897	875	976	768
Lease operating expenses per Mcfe	$ 0.93	$ 0.90	$ 0.87	$ 0.92	$ 0.91
General and administrative expenses per Mcfe	$ 0.19 (2)	$ 0.22 (3)	$ 0.22 (4)	$ 0.21	$ 0.24
Taxes, other than income taxes per Mcfe	$ 0.09 (5)	$ 0.10	$ 0.10 (6)	$ 0.10	$ 0.11
Proved reserves at year-end:					
Natural gas *(Bcf)*	8,044	11,126	4,866	5,917	9,809
Oil *(MMBbls)*	69.0	65.6	10.5	8.8	37.6
NGLs *(MMBbls)*	577.1	542.4	53.9	40.9	118.7
Total reserves *(Bcfe)*	11,921	14,775	5,253	6,215	10,747
Midstream					
Volumes marketed *(Bcfe)*	1,163	1,067	1,062	1,127	904
Volumes gathered *(Bcf)* (7)	382	499	601	799	963

(1) Capital investments include a decrease of $53 million for 2018, 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. There was no impact to 2017.

(2) Excludes $36 million of restructuring charges and $9 million of legal settlement charges for 2018.

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

(4) Excludes $78 million of restructuring and other one-time charges for 2016.

(5) Excludes $1 million of restructuring charges for 2018.

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

(7) Our Fayetteville Shale related gathering assets were sold on December 3, 2018. Substantially all of the gathered volumes in each of the years presented relate to gathering assets that have been divested.

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

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

OVERVIEW

Background

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

E&P. Our primary business is the exploration for and production of natural gas, oil and NGLs, with our ongoing operations focused on the development of unconventional natural gas reservoirs located in Pennsylvania and West Virginia. 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, our properties in Pennsylvania and West Virginia are herein referred to as the "Appalachian Basin." We also have drilling rigs located in Pennsylvania and West Virginia, and we provide certain oilfield products and services, principally serving our E&P operations though vertical integration.

On August 30, 2018, we entered into an agreement to sell 100% of the equity in certain of our subsidiaries that conducted our operations in Arkansas, which were primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale, for $1,865 million, subject to customary adjustments. In early December 2018, we completed the Fayetteville Shale sale, resulting in net proceeds of $1,650 million, following adjustments due primarily to the net cash flows from the economic effective date of July 1, 2018, to the closing date.

Midstream. Our marketing activities capture opportunities that arise through the marketing and transportation of natural gas, oil, and NGLs produced in our E&P operations. In December 2018, we divested almost all of our gathering assets as part of the Fayetteville Shale sale.

Changes in 2018. At the beginning of 2018, we announced our strategy to reposition the Company through portfolio optimization, balance sheet management and leveraging our technical, commercial and operational expertise to improve margins. We sharpened our focus on developing our high-value, liquids-rich Appalachian basin assets. We strengthened our balance sheet through asset monetization and debt reduction by entering into a new reserve-based credit facility and paying down outstanding debt, which improved our debt maturity profile while preserving financial and operational flexibility. We sold our Fayetteville Shale assets, further reducing our debt, repurchasing shares and earmarking proceeds for our 2019 and 2020 capital investment programs and other general corporate purposes. We made further technological advances in drilling precision and completion optimization that enhanced well productivity and economics, resulting in improved returns, and we focused on identifying and implementing opportunities to lower our overall cost structure. We added to our derivative portfolio, protecting approximately 479 Bcfe and 117 Bcfe of our forecasted 2019 and 2020 production, respectively, from price volatility through the use of commodity derivatives.

Recent Financial and Operating Results

Significant operating and financial highlights for 2018 include:

Total Company

- Net income attributable to common stock of $535 million, or $0.93 per diluted share, down from a net income attributable to common stock of $816 million, or $1.63 per diluted share, in 2017. The decrease was primarily due to a loss on unsettled derivatives of $24 million in 2018 as compared to a gain of $451 million in 2017. Excluding the impact of unsettled derivatives, net income attributable to common stock was up $194 million, or 53%, compared to 2017.
- Net cash provided by operating activities of $1,223 million was up 11% from $1,097 million in 2017.
- Total capital invested of $1,248 million was down 3% from $1,293 million in 2017.
- Total debt of approximately $2.3 billion decreased by $2.1 billion, or 47%, compared to 2017.
- We repurchased approximately 39 million shares of our common stock for $180 million.

E&P

- E&P segment operating income of $794 million was up 45%, compared to $549 million in 2017.
- Year-end reserves of 11,921 Bcfe decreased 19% from 14,775 Bcfe at the end of 2017. Excluding the 3,443 Bcfe of reserves sold during the year, year-end reserves were up 589 Bcfe, resulting from 946 Bcfe of production offset by 1,009 Bcfe of additions and 526 Bcfe of revisions.
- Total net production of 946 Bcfe, including 702 Bcfe from our Appalachian Basin and 243 Bcf from the Fayetteville Shale, increased 5% from 2017, and was comprised of 85% natural gas and 15% oil and NGLs.
- Excluding the effect of derivatives, our realized natural gas price of $2.45 per Mcf, realized oil price of $56.79 per barrel and realized NGL price of $17.91 per barrel increased 10%, 32% and 24%, respectively, from 2017.
- The E&P segment invested $1,231 million in capital drilling 106 wells, completing 119 wells and placing 138 wells to sales.

Outlook

We expect to continue to exercise capital discipline through a fully-funded 2019 capital investment program. We remain committed to our focus on optimizing our portfolio by concentrating our efforts on our highest return assets, looking for opportunities to maximize margins in each core area of our business and further developing our knowledge of our asset base. We believe our industry will continue to face challenges due to the uncertainty of natural gas, oil and NGL prices in the United States, changes in laws, regulations and investor sentiment, and other key factors described above under “Risk Factors.”

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. Restructuring charges, interest expense, gain (loss) on derivatives, loss on early extinguishment of debt and income tax expense are discussed on a consolidated basis.

E&P

The table below includes the effects of the sale of the E&P assets included in the Fayetteville Shale sale which closed on December 3, 2018.

(in millions)	For the years ended December 31, 2018	2017	2016
Revenues	$ 2,525	$ 2,086	$ 1,413
Impairment of natural gas and oil properties	–	–	2,321
Operating costs and expenses	1,731 [(1)]	1,537	1,491 [(2)]
Operating income (loss)	$ 794	$ 549	$ (2,399)
Gain (loss) on derivatives, settled [(3)]	$ (94)	$ (27)	$ 36

(1) Includes $37 million of restructuring charges, an $18 million loss on the sale of assets and $15 million of non-full cost pool asset impairments.

(2) Includes $81 million of restructuring and other one-time charges for the year ended December 31, 2016.

(3) Represents the gain (loss) on settled commodity derivatives and includes $1 million and $5 million amortization of premiums paid related to certain natural gas call options for the year ended December 31, 2018 and 2017, respectively.

Operating Income

- Operating income for the E&P segment increased $245 million for the year ended December 31, 2018, compared to 2017 due to a $439 million increase in revenues, partially offset by a $194 million increase in operating costs. In 2018, operating costs included $37 million in restructuring charges, an $18 million loss on sale of assets and a $15 million impairment of non-full cost pool assets.
- E&P segment operating income for the year ended December 31, 2016 includes an impairment of natural gas and oil properties of $2.3 billion. Excluding the 2016 impairment, our E&P segment operating income increased $627 million for the year ended December 31, 2017, compared to the same period in 2016, due to a $673 million increase in revenues, partially offset by a $46 million increase in operating costs.

Revenues

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

(in millions except percentages)	For the years ended December 31, Natural Gas	Oil	NGLs	Total
2017 sales revenues	$ 1,775	$ 101	$ 206	$ 2,082
Changes associated with prices	177	46	68	291
Changes associated with production volumes	22	46	79	147
2018 sales revenues	$ 1,974	$ 193	$ 353	$ 2,520
Increase from 2017	11%	91%	71%	21%

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

In addition to the sales revenues detailed above, our E&P segment had $5 million and $4 million of other operating revenues, primarily related to water sales to third-party operators for the years ended December 31, 2018 and 2017, respectively.

Production Volumes

	For the years ended December 31,				
	2018	Increase/ (Decrease)	2017	Increase/ (Decrease)	2016
Natural Gas *(Bcf)*					
Northeast Appalachia	**459**	16%	395	13%	350
Southwest Appalachia	**105**	24%	85	37%	62
Fayetteville Shale (1)	**243**	(23%)	316	(16%)	375
Other	**–**	(100%)	1	0%	1
Total	**807**	1%	797	1%	788
Oil *(MBbls)*					
Southwest Appalachia	**3,355**	51%	2,228	9%	2,041
Other	**52**	(47%)	99	(34%)	151
Total	**3,407**	46%	2,327	6%	2,192
NGL *(MBbls)*					
Southwest Appalachia	**19,679**	39%	14,193	15%	12,317
Other	**27**	(48%)	52	(5%)	55
Total	**19,706**	38%	14,245	15%	12,372
Production volumes by area *(Bcfe)*					
Northeast Appalachia	**459**	16%	395	13%	350
Southwest Appalachia (2)	**243**	33%	183	24%	148
Fayetteville Shale (1)	**243**	(23%)	316	(16%)	375
Other	**1**	(67%)	3	50%	2
Total	**946**	5%	897	3%	875
Production percentage *(Bcfe)*					
Natural gas	**85%**		88%		91%
Oil	**2%**		2%		1%
NGL	**13%**		10%		8%
Total	**100%**		100%		100%

(1) The Fayetteville Shale assets and associated reserves were sold on December 3, 2018.

(2) Approximately 240 Bcfe, 179 Bcfe and 148 Bcfe for the years ended December 31, 2018, 2017 and 2016, respectively, were produced from the Marcellus Shale formation.

- Production volumes for our E&P segment increased by 49 Bcfe for the year ended December 31, 2018, compared to the same period in 2017, as increased production volumes from Northeast and Southwest Appalachia more than offset decreased natural gas production volumes in the Fayetteville Shale, which reflects only eleven months of production in 2018 as a result of its sale in December 2018.
- E&P segment production volumes increased 22 Bcfe for the year ended December 31, 2017, compared to the same period in 2016, as increased natural gas production volumes in Northeast and Southwest Appalachia more than offset decreased production volumes in the Fayetteville Shale.

Commodity Prices

The price we expect to receive for our production is a critical factor in determining the capital investments we make to develop our properties. Commodity prices fluctuate due to a variety of factors we cannot control or predict, including increased supplies of natural gas, oil or NGLs due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources. These factors impact supply and demand, which in turn determine the sales prices for our production. In addition to these factors, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. We will continue to evaluate the commodity price environments and adjust the pace of our activities in order to not exceed our fully-funded 2019 capital investment program.

	For the years ended December 31,				
	2018	Increase/ (Decrease)	2017	Increase/ (Decrease)	2016
Natural Gas Price:					
NYMEX Henry Hub Price *($/MMBtu)* [1]	$ 3.09	(1%)	$ 3.11	26%	$ 2.46
Discount to NYMEX [2]	(0.64)	(27%)	(0.88)	1%	(0.87)
Average realized gas price per Mcf, excluding derivatives	$ 2.45	10%	$ 2.23	40%	$ 1.59
Gain (loss) on settled financial basis derivatives *($/Mcf)*	(0.04)		(0.01)		0.03
Gain (loss) on settled commodity derivatives *($/Mcf)*	(0.06)		(0.03)		0.02
Average realized gas price per Mcf, including derivatives	$ 2.35	7%	$ 2.19	34%	$ 1.64
Oil Price:					
WTI oil price *($/Bbl)*	$ 64.77	27%	$ 50.96	18%	$ 43.32
Discount to WTI	(7.98)	2%	(7.84)	(35%)	(12.12)
Average oil price per Bbl, excluding derivatives	$ 56.79	32%	$ 43.12	38%	$ 31.20
Loss on settled derivatives *($/Bbl)*	(0.72)		–		–
Average oil price per Bbl, including derivatives	$ 56.07	30%	$ 43.12	38%	$ 31.20
NGL Price:					
Average net realized NGL price per Bbl, excluding derivatives	$ 17.91	24%	$ 14.46	94%	$ 7.46
Gain (loss) on settled derivatives *($/Bbl)*	(0.68)		0.02		–
Average net realized NGL price per Bbl, including derivatives	$ 17.23	19%	$ 14.48	94%	$ 7.46
Percentage of WTI, excluding derivatives	28%		28%		17%
Total Weighted Average Realized Price:					
Excluding derivatives *($/Mcfe)*	$ 2.66		$ 2.32		$ 1.62
Including derivatives *($/Mcfe)*	$ 2.57		$ 2.29		$ 1.66

(1) Based on last day settlement prices from monthly futures contracts.

(2) This discount includes a basis differential, a heating content adjustment, physical basis sales, third-party transportation charges and fuel charges, and excludes financial basis hedges.

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

We regularly enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas, oil and NGL 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, Quantitative and Qualitative Disclosures about Market Risk, of this Annual Report, Note 5 to the consolidated financial statements included in this Annual Report, and our derivative risk factor for additional discussion about our derivatives and risk management activities.

The table below presents the amount of our future production in which the basis is protected as of December 31, 2018:

	Volume *(Bcf)*	Basis Differential
Basis Swaps – Natural Gas		
2019	107	$ (0.29)
2020	59	(0.44)
Total	166	
Physical Sales Arrangements – Natural Gas		
2019	110	$ (0.16)
2020	45	(0.23)
Total	155	

In addition to protecting basis, the table below presents the amount of our future production in which price is financially protected as of December 31, 2018:

	2019	2020	2021
Natural gas *(Bcf)*	443	108	37
Oil *(MBbls)*	675	732	–
Propane *(MBbls)*	1,689	–	–
Ethane *(MBbls)*	3,687	732	–
Total financial protection on future production *(Bcfe)*	479	117	37

We refer you to Note 5 to the consolidated financial statements included in this Annual Report for additional details about our derivative instruments.

Operating Costs and Expenses

(in millions except percentages)	For the years ended December 31, 2018	Increase/ (Decrease)	2017	Increase/ (Decrease)	2016
Lease operating expenses	**$ 878**	9%	$ 809	6%	$ 761
General & administrative expenses	**186** (1)	(8%)	202 (2)	(1%)	204
Restructuring charges	**37**	100%	–	(100%)	70
Taxes, other than income taxes	**83**	(3%)	86	1%	85
Full cost pool amortization	**479**	18%	405	23%	329
Non-full cost pool DD&A	**35**	0%	35	(17%)	42
Impairments	**15**	100%	–	0%	–
Loss on sale of assets	**18**	100%	–	0%	–
Total operating costs	**$ 1,731** (1)	13%	$ 1,537 (2)	3%	$ 1,491

Average unit costs per Mcfe:	For the years ended December 31, 2018	Increase/ (Decrease)	2017	Increase/ (Decrease)	2016
Lease operating expenses	**$ 0.93**	3%	$ 0.90	3%	$ 0.87
General & administrative expenses	**$ 0.19** (3)	(14%)	$ 0.22 (4)	0%	$ 0.22 (5)
Taxes, other than income taxes	**$ 0.09** (6)	(10%)	$ 0.10	0%	$ 0.10 (7)
Full cost pool amortization	**$ 0.51**	13%	$ 0.45	18%	$ 0.38

(1) Includes $9 million of legal settlement charges for the year ended December 31, 2018.

(2) Includes $5 million of legal settlement charges for the year ended December 31, 2017.

(3) Excludes $36 million of restructuring charges and $9 million of legal settlement charges for the year ended December 31, 2018.

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

(5) Excludes $67 million of restructuring charges and $11 million of legal settlements for the year ended December 31, 2016.

(6) Excludes $1 million of restructuring charges for the year ended December 31, 2018.

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

Lease Operating Expenses

- On a per Mcfe basis, lease operating expenses increased $0.03 for the year ended December 31, 2018, compared to 2017, primarily due to additional NGL processing fees associated with our increased production in Southwest Appalachia.
- Lease operating expenses per Mcfe increased $0.03 for the year ended December 31, 2017, compared to 2016, primarily due to increased transportation and processing costs, as our production growth shifted toward the Appalachian Basin.

General and Administrative Expenses

- General and administrative expenses decreased in 2018, compared to 2017, as a $20 million decrease in costs resulting from the mid-year implementation of cost reductions and decreased personnel costs was partially offset by a $4 million increase in legal settlement charges.
- On a per Mcfe basis, excluding restructuring and legal settlement charges, general and administrative expenses per Mcfe decreased for the year ended December 31, 2018, compared to 2017, due to a 10% decrease in expenses and a 5% increase in production volumes.

- On a per Mcfe basis, excluding restructuring and legal settlement charges, general and administrative expenses per Mcfe remained flat for the year ended December 31, 2017, compared to 2016, as a slight increase in expenses was offset by a 3% increase in production volumes.

Taxes, Other than Income Taxes

- Taxes other than income taxes per Mcfe may vary from period to period due to changes in ad valorem and severance taxes that result from the mix of our production volumes and fluctuations in commodity prices. Excluding $1 million of restructuring charges in 2018, taxes, other than income taxes, per Mcfe decreased $0.01 per Mcfe for the year ended December 31, 2018, compared to the same period in 2017, primarily due to an $8 million severance tax refund related to a favorable assessment on deductible expenses in Southwest Appalachia, a $1 million severance tax refund related to a favorable assessment on deductible expenses in the Fayetteville Shale, favorable property tax assessments, and property and sales tax refunds recorded in the first quarter of 2018.
- On a per Mcfe basis, taxes, other than income taxes, remained flat for the year ended December 31, 2017 compared to 2016 as a slight increase in expense was more than offset by an increase in production volumes.

Full Cost Pool Amortization

- Our full cost pool amortization rate increased $0.06 per Mcfe for the year ended December 31, 2018, as compared to 2017. The increase in the average amortization rate resulted primarily from the addition of future development costs associated with proved undeveloped reserves recognized as a result of improved commodity prices.
- The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling impairments, proceeds from the sale of properties that reduce the full cost pool, and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserve changes.
- Unevaluated costs excluded from amortization were $1.8 billion at December 31, 2018, and 2017, compared to $2.1 billion at December 31, 2016. The unevaluated costs excluded from amortization slightly decreased, as compared to 2017, as the evaluation of previously unevaluated properties totaling $361 million in 2018 was only partially offset by the impact of $299 million of unevaluated capital invested during the same period.

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

Impairments

In accordance with accounting guidance for Property, Plant and Equipment, assets held for sale are measured at the lower of carrying value or fair value less costs to sell. Because the assets outside the full cost pool met the criteria for held for sale accounting in the third quarter of 2018, we determined the carrying value of certain non-full cost pool E&P assets exceeded the fair value less costs to sell. As a result, an impairment charge of $15 million was recorded during the year ended December 31, 2018.

Midstream

The table below reflects the sale of gas gathering assets included in the Fayetteville Shale sale which closed on December 3, 2018, resulting in a net gain and approximately eleven months of gathering activity for the year ended December 31, 2018.

	For the years ended December 31,				
(in millions except percentages)	**2018**	Increase/ (Decrease)	2017	Increase/ (Decrease)	2016
Marketing revenues	**$ 3,497**	22%	$ 2,867	31%	$ 2,191
Gas gathering revenues	**248**	(25%)	331	(12%)	378
Marketing purchases	**3,455**	22%	2,824	32%	2,145
Operating costs and expenses	**166** (1)	(11%)	197	(8%)	215 (2)
Impairments	**155**	100%	–	0%	–
Gain on sale of assets, net	**35**	483%	6	100%	–
Operating income	**$ 4**	(98%)	$ 183	(12%)	$ 209
Volumes marketed *(Bcfe)*	**1,163**	9%	1,067	0%	1,062
Volumes gathered *(Bcf)*	**382**	(23%)	499	(17%)	601
Affiliated E&P natural gas production marketed	**93%**		96%		93%
Affiliated E&P oil and NGL production marketed	**66%**		63%		65%

(1) Includes $2 million of restructuring charges for the year ended December 31, 2018.

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

Operating Income

- Operating income for the year ended December 31, 2018 included $155 million of impairments and $2 million of restructuring charges. The impairments were comprised of $145 million related to our gathering assets included in the Fayetteville Shale sale, and $10 million related to other non-core gathering assets. Excluding the impairment and restructuring charges, operating income from our Midstream segment decreased $22 million for the year ended December 31, 2018, compared to 2017, primarily due to an $83 million decrease in gas gathering revenues and a $1 million decrease in marketing margin, partially offset by a $33 million decrease in operating costs and expenses and a $29 million increase in gain on sale of assets, net.
- Operating income decreased $26 million for the year ended December 31, 2017, compared to 2016, primarily due to a $47 million decrease in gas gathering revenues and a $3 million decrease in marketing margin, partially offset by an $18 million decrease in operating costs and expenses and a $6 million gain on the sale of certain compressor equipment.
- The margin generated from marketing activities was $42 million, $43 million and $46 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Margins are driven primarily by volumes marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. Increases and decreases in marketing revenues due to changes in commodity prices and volumes marketed are largely offset by corresponding changes in marketing purchase expenses. We enter into derivative contracts from time to time with respect to our marketing activities to provide margin protection. For more information about our derivatives and risk management activities, we refer you to Item 7A of Part II of this Annual Report and Note 5 to the consolidated financial statements included in this Annual Report.

Revenues

- Revenues from our marketing activities increased $630 million for the year ended December 31, 2018, compared to 2017, primarily due to a 12% increase in the price received for volumes marketed and a 96 Bcfe increase in the volumes marketed.
- For the year ended December 31, 2017, revenues from our marketing activities increased $676 million, compared to 2016, primarily due to a 30% increase in the price received for volumes marketed and a 5 Bcfe increase in the volumes marketed.
- Gas gathering revenues decreased $83 million for the year ended December 31, 2018, compared to the year ended December 31, 2017, primarily due to decreased volumes gathered in the Fayetteville Shale along with only approximately eleven months of gathering activity in 2018 as we sold our Fayetteville Shale gathering operations in early December 2018.

- Gas gathering revenues decreased $47 million for the year ended December 31, 2017, compared to the year ended December 31, 2016, primarily due to decreasing volumes gathered in the Fayetteville Shale.

Operating Costs and Expenses

- Operating costs and expenses for the year ended December 31, 2018 included $2 million of restructuring charges. Excluding these charges, operating costs and expenses decreased $33 million for the year ended December 31, 2018 compared to the year ended December 31, 2017, primarily due to an $18 million decrease in depreciation, an $8 million decrease in general and administrative expenses, a $6 million decrease in gathering operating expenses and a $1 million decrease in taxes other than income taxes. In addition, the sale of our gathering assets in early December 2018 resulted in only approximately eleven months of gathering operations for 2018.
- Operating costs and expenses for the year ended December 31, 2016 included $3 million of restructuring charges. Excluding this charge, operating costs and expenses decreased $15 million for the year ended December 31, 2017 compared to the year ended December 31, 2016, primarily due to reduced compression and personnel costs due to lower activity levels as a result of decreasing volumes gathered in the Fayetteville Shale.

Impairments

In the second quarter of 2018, we recorded an impairment charge of $10 million related to certain non-core gathering assets. In the third quarter of 2018, the Fayetteville Shale gathering assets were classified as held for sale. As such, we determined the carrying value of our gathering assets held for sale exceeded the fair value less the costs to sell. As a result, we recorded an impairment charge of $145 million in 2018.

Consolidated

Restructuring Charges

On June 27, 2018, we announced a workforce reduction plan, which resulted primarily from our previously announced study of structural, process and organizational changes to enhance shareholder value and continues with respect to other aspects of our business and activities. Affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were cancelled. We recognized $23 million in restructuring charges related to the workforce reduction plan for the year ended December 31, 2018.

In December 2018, we closed the sale of the equity in certain of our subsidiaries that owned and operated our Fayetteville Shale E&P and related midstream gathering assets in Arkansas. As part of this transaction, most employees associated with those assets became employees of the buyer although the employment of some was or will be terminated. All affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited. We incurred $12 million in severance costs related to the Fayetteville Shale sale for the year ended December 31, 2018 and have recognized these costs as restructuring charges.

As a result of the Fayetteville Shale sale, we incurred $4 million in charges primarily related to office consolidation and have recognized these costs as restructuring charges.

For the year ended December 31, 2018, we recognized total restructuring charges of $39 million, of which $33 million was related to cash severance, including payroll taxes withheld and professional fees. The plans had been substantially implemented as of the end of the year, however, certain employment terminations were delayed into 2019. As of December 31, 2018, we had recorded a liability of $5 million related to severance to be paid out in 2019.

In January 2016, we announced a 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 $73 million for the year ended December 31, 2016.

Interest Expense

(in millions except percentages)	For the years ended December 31, 2018	Increase/ (Decrease)	2017	Increase/ (Decrease)	2016
Gross interest expense:					
Senior notes	$ 196	11%	$ 177	(3%)	$ 183
Credit arrangements	35	(44%)	62	44%	43
Amortization of debt costs	8	(11%)	9	(36%)	14
Total gross interest expense	239	(4%)	248	3%	240
Less: capitalization	(115)	2%	(113)	(26%)	(152)
Net interest expense	$ 124	(8%)	$ 135	53%	$ 88

- Interest expense related to our senior notes increased for the year ended December 31, 2018, as compared to the same period in 2017, due to the higher average interest rates associated with our senior notes due 2026 and 2027, which were issued in September 2017.
- Interest expense related to our senior notes decreased for the year ended December 31, 2017, as compared to the same period in 2016, as a decrease in interest expense related to the gradual redemption of our 7.50% Senior Notes due in February 2018, which began in July 2016 and completed in May 2017, was only partially offset by increased interest expense which resulted from the issuance of new senior notes in September 2017.
- Interest expense related to our credit arrangements decreased for the year ended December 31, 2018, as compared to the same period in 2017, primarily due to the extinguishment of our 2016 term loan and entering into our revolving credit facility in April 2018, which decreased our outstanding borrowing amount, and the repayment of our revolving credit facility borrowings with a portion of the net proceeds from the Fayetteville Shale sale.
- For the year ended December 31, 2017, interest expense related to our credit arrangements increased, as compared to the same period in 2016, due to increased outstanding borrowings and higher interest rates.
- Capitalized interest increased $2 million for the year ended December 31, 2018, compared to the same period in 2017, and increased as a percentage of gross interest expense due to our increased cost of borrowing. The decreases in capitalized interest for the year ended December 31, 2017, as compared to the same period in 2016, were primarily due to the continued evaluation of a portion of our Southwest Appalachia assets.

Gain (Loss) on Derivatives

(in millions)	For the years ended December 31, 2018	2017	2016
Gain (loss) on unsettled derivatives	$ (24)	$ 451	$ (373)
Gain (loss) on settled derivatives	(94)[1]	(29)[2]	34
Total gain (loss) on derivatives	$ (118)[1]	$ 422[2]	$ (339)

(1) Includes $1 million of premiums paid related to certain natural gas call options for the year ended December 31, 2018, which is included in gain (loss) on derivatives on the consolidated statement of operations.

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

We refer you to Note 5 to the consolidated financial statements included in this Annual Report for additional details about our gain (loss) on derivatives.

Loss on Early Extinguishment of Debt

- In December 2018, we used a portion of the net proceeds from our Fayetteville Shale sale to repurchase $40 million of our senior notes due January 2020, $787 million of our senior notes due March 2022 and $73 million of our senior notes due January 2025. We recognized a loss of $9 million for the redemption of these senior notes, which included $2 million of premiums paid.

- Concurrent with the closing of our revolving credit facility on April 26, 2018, we repaid our $1,191 million 2016 secured term loan balance and recognized a loss on early debt extinguishment of $8 million on the consolidated statements of operations related to the unamortized debt issuance expense.
- In September 2017, we used the net proceeds of approximately $1.1 billion from our September 2017 senior notes offering to repurchase approximately $758 million of our 2020 Senior Notes and to repay the remaining $327 million principal amount outstanding of our 2015 Term Loan. We recognized a loss of $59 million for the redemption of these senior notes which included $53 million of premiums paid.
- In the first half of 2017, we redeemed the remaining $276 million principal amount outstanding of our 2018 Senior Notes, recognizing a loss of $11 million.
- During the third quarter of 2016, we used proceeds from our $1,247 million July 2016 equity offering to purchase and retire $700 million of our outstanding senior notes due in the first quarter of 2018 and retire $375 million of our $750 million term loan entered into in November 2015. We recognized a loss of $51 million for the redemption of these senior notes, which included $50 million of premiums paid.

Income Taxes

	For the years ended December 31,		
(in millions except percentages)	**2018**	2017	2016
Income tax expense (benefit)	**$ 1**	$ (93)	$ (29)
Effective tax rate	**0%**	(10%)	1%

- The income tax expense recognized for the year ended December 31, 2018 increased, as compared with 2017, primarily due to state income taxes resulting from the Fayetteville Shale sale partially offset by a benefit recorded related to an increased alternative minimum tax receivable, as well as changes to the overall valuation allowance activity during 2018.
- The income tax benefits recognized for the year ended December 31, 2017 primarily resulted from changes in federal tax legislation enacted under the Tax Cuts and Jobs Act (Tax Reform) which will allow us to recover certain alternative minimum tax credit carryovers, along with the expiration of a portion of our uncertain tax provision.
- Our low effective tax rate is the result of our recognition of a valuation allowance that reduced the deferred tax asset primarily related to our current net operating loss carryforward, as well as changes to the deferred tax rate enacted under the recent Tax Reform. A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized.

We refer you to Note 10 to the consolidated financial statements included in this Annual Report for additional discussion about our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

We depend on funds generated from our operations, our cash and cash equivalents balance, our revolving credit facility and capital markets as our primary sources of liquidity. Although we have financial flexibility with our cash balance and the ability to draw on our $2.0 billion revolving credit facility (less outstanding letters of credit which were approximately $0.1 billion as of December 31, 2018), we continue to be committed to our capital discipline strategy of investing within our cash flow from operations net of changes in working capital, supplemented by a portion of the net proceeds from the Fayetteville Shale sale.

As discussed in Note 3 to the consolidated financial statements included in this Annual Report, in December 2018, we closed on the Fayetteville Shale sale and received net proceeds of approximately $1,650 million, which included preliminary purchase price adjustments of approximately $215 million primarily related to the net cash flows from the economic effective date to the closing date. From the net proceeds received, $914 million was used to repurchase $900 million of our outstanding senior notes along with related accrued interest and retirement premiums paid, as discussed in Note 8 to the consolidated financial statements included in this Annual Report, and through December 31, 2018, $180 million has been used to repurchase approximately 39 million shares of our outstanding common stock. We may use a portion of the remaining net proceeds from the Fayetteville Shale sale to supplement cash flow related to the further development of our liquids-rich Appalachian assets in order to accelerate the path to self-funding and for general corporate purposes. Pending these other uses, a portion of these remaining net proceeds have been used to repay revolving credit facility borrowings until investments are made.

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. Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. See "Risk Factors" in Item 1A, "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A and Note 5 to the consolidated financial statements included in this Annual Report for further details.

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

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

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

Credit Arrangements and Financing Activities

On April 26, 2018, as part of our strategic effort to increase financial flexibility and reduce costs, we replaced our credit facilities (which consisted of a $1,191 million secured term loan and two unsecured revolving credit facilities totaling $809 million) with a new revolving credit facility. The 2018 revolving credit facility initially had a maximum borrowing capacity of $3.5 billion and commitments of $2.0 billion and is subject to semiannual borrowing base redeterminations by the lenders in April and October. Borrowings also may not exceed the permitted lien limitations in our senior note indentures. The borrowing base is subject to change based primarily on drilling results, commodity prices, the level of capital investing and operating costs. In October 2018, our borrowing base was reduced from an initial $3.2 billion to $3.1 billion and, upon the closing of the Fayetteville Shale sale in December 2018, was reduced to $2.1 billion with our commitments remaining at $2.0 billion. The permitted lien provisions in the senior note indentures currently limit liens securing indebtedness to the greater of $2.0 billion and 25% of adjusted consolidated net tangible assets. The 2018 revolving credit facility matures in April 2023, and as of December 31, 2018, had no borrowings outstanding. We also have $112 million in letters of credit outstanding but not drawn with banks in our credit facility.

By entering into the 2018 revolving credit facility, we realized certain benefits including:

- Reduction in debt outstanding and simplification of our capital structure by consolidating the components of the 2016 credit facility into a senior secured revolving credit facility and by terminating our 2013 credit facility (consisting of an unsecured $66 million revolving credit facility).
- Reduced interest expense due to both the termination of the $1,191 million secured term loan and lower interest margins associated with the 2018 revolving credit facility.
- Greater access to liquidity by extending the maturity from December 2020 (under the 2016 credit facility) to April 2023 under the 2018 revolving credit facility.
- Increased financial flexibility by eliminating certain provisions in the 2016 credit facility associated with minimum liquidity requirements and restrictions on asset sale proceeds.

In the fourth quarter of 2018, we entered into hedges that, when added to then-existing hedges including hedges put in place as part of the Fayetteville Shale sale that the buyer was obligated to assume at closing of that sale, exceeded a cap on hedges for the month of December 2018 under a covenant under our credit agreement. In conjunction with the closing, the buyer paid for the settlement of the December 2018 hedges it was to assume. The lenders have subsequently waived all matters associated with this default. Otherwise, as of December 31, 2018, we were in compliance with all of the remaining covenants of our revolving credit facility in all material respects. Although we do not anticipate any future violations of the financial covenants, our ability to comply with these covenants is in part dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and liquids. We refer you to Note 8 to the consolidated financial statements included in this Annual Report for additional discussion of the covenant requirements of our revolving credit facility.

The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the revolving credit facility. Although we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet their obligation to us. We refer you to Note 8 to the consolidated financial statements included in this Annual Report for additional discussion of our revolving credit facility.

In December 2018, we closed on the Fayetteville Shale sale resulting in net proceeds of approximately $1,650 million, following customary preliminary purchase price adjustments of $215 million primarily related to the net cash flows from the economic effective date to the closing date and certain other working capital adjustments. We used a portion of the net proceeds to repurchase $900 million of our outstanding senior notes.

Because of the focused work on refinancing and repayment of our debt during 2017 and 2018, only $265 million, or 11%, of our outstanding debt balance as of December 31, 2018 will come due prior to 2025, with only $52 million of that coming due in the next three years. We expect to save approximately $80 million in annual debt interest from our 2018 debt reduction efforts.

At February 26, 2019, we had a long-term issuer credit rating of Ba2 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 upgrades or downgrades in our public debt ratings by Moody's or S&P could decrease or increase our cost of funds, respectively.

Cash Flows

	For the years ended December 31,		
(in millions)	**2018**	2017	2016
Net cash provided by operating activities	**$ 1,223**	$ 1,097	$ 498
Net cash provided by (used in) investing activities	**359**	(1,252)	(162)
Net cash used in financing activities	**(2,297)**	(352)	1,072

Cash Flow from Operations

	For the years ended December 31,		
(in millions)	**2018**	2017	2016
Net cash provided by operating activities	**$ 1,223**	$ 1,097	$ 498
Add: Changes in working capital	**90**	49	99
Net cash provided by operating activities, net of changes in working capital	**1,313**	1,146	597

- Net cash provided by operating activities increased 11% or $126 million for the year ended December 31, 2018, compared to the same period in 2017, primarily due to an increase in revenues resulting from a 12% increase in our weighted average realized commodity price, including derivatives, and a 5% increase in production volumes.
- For the year ended December 31, 2017, net cash provided by operating activities increased 120% or $599 million, compared to the same period in 2016, primarily due to an increase in revenues resulting from increased realized commodity prices and a 3% increase in production volumes.
- Net cash generated from operating activities, net of changes in working capital, provided 105% of our cash requirements for capital investments for the year ended December 31, 2018, compared to providing 89% and 92% of our cash requirements for capital investments for the same periods in 2017 and 2016, respectively, reflecting our capital discipline strategy of investing within our cash flow from operations, net of changes in working capital.

Cash Flow from Investing Activities

- Total E&P capital investing decreased $17 million for the year ended December 31, 2018, compared to the same period in 2017, due to an $11 million decrease in direct E&P capital investing and a $6 million decrease in capitalized interest and internal costs. Of the $1,231 million invested in our E&P segment for the year ended December 31, 2018, 95% was invested in the Appalachian Basin.
- For the year ended December 31, 2017, total E&P capital investing increased $625 million, compared to the same period in 2016, due to a $652 million increase in direct E&P capital investing which was only partially offset by a $27 million decrease in capitalized interest and internal costs. The significant increase in 2017 capital investing resulted from our decision to suspend drilling activity in the first half of 2016 due to an unfavorable commodity price environment. We began increasing activity in the second half of 2016.
- The increase in capitalized interest for the year ended December 31, 2018, as compared to the same period in 2016, was primarily due to the increase in cost of borrowing as we reduced our near-term debt which had lower interest rates.
- The decrease in capitalized interest for the year ended December 31, 2017, as compared to the same period in 2016, was primarily due to the continued evaluation of a portion of our Southwest Appalachia assets acquired in December 2014.
- Midstream capital investing decreased $23 million for the year ended December 31, 2018, compared to the same period in 2017, primarily due to the shift in focus to our core E&P assets.
- For the year ended December 31, 2017, Midstream capital investing increased $11 million, compared to the same period in 2016, primarily due to the purchase of several leased compressors in 2017 which were subsequently sold to third parties for a net gain of $6 million.

	For the years ended December 31,		
(in millions)	**2018**	2017	2016
Cash flows from investing activities:			
Additions to properties and equipment	**$ 1,290**	$ 1,268	$ 593
Adjustments for capital investments:			
Changes in capital accruals	**(53)**	–	43
Other [(1)]	**11**	25	12
Total capital investing	**$ 1,248**	$ 1,293	$ 648

(1) Includes capitalized non-cash stock-based compensation and costs to retire assets, which are classified as cash used in operating activities.

Capital Investing

	For the years ended December 31,				
(in millions except percentages)	**2018**	Increase/ (Decrease)	2017	Increase/ (Decrease)	2016
E&P capital investing	**$ 1,231**		$ 1,248		$ 623
Midstream capital investing	**9**		32		21
Other capital investing	**8**		13		4
Total capital investing	**$ 1,248**	(3%)	$ 1,293	100%	$ 648

	For the years ended December 31,		
(in millions)	**2018**	2017	2016
E&P Capital Investments by Type			
Exploratory and development drilling, including workovers	**$ 895**	$ 878	$ 358
Acquisitions of properties	**51**	86	23
Seismic expenditures	**4**	7	1
Water infrastructure projects	**60**	37	2
Drilling rigs, sand facility and other	**15**	28	–
Capitalized interest and expenses	**206**	212	239
Total E&P capital investments	**$ 1,231**	$ 1,248	$ 623
E&P Capital Investments by Area			
Northeast Appalachia	**$ 422**	$ 489	$ 204
Southwest Appalachia	**691**	547	288
Fayetteville Shale	**33**	114	86
New Ventures & Other [(1)]	**85**	98	45
Total E&P capital investments	**$ 1,231**	$ 1,248	$ 623

(1) Includes $60 million and $37 million for the years ended December 31, 2018 and 2017, respectively, related to our water infrastructure project.

	For the years ended December 31,		
	2018	2017	2016
Gross Operated Well Count Summary:			
Drilled	**106**	134	62
Completed	**119**	151	86
Wells to sales	**138**	166	85

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

Cash Flow from Financing Activities

	For the years ended December 31,		
(in millions except percentages)	**2018**	2017	Increase/ (Decrease)
Debt [1]	**$ 2,318**	$ 4,391	$ (2,073)
Equity	**$ 2,362**	$ 1,979	$ 383
Total debt to capitalization ratio	**50%**	69%	
Debt [1]	**$ 2,318**	$ 4,391	$ (2,073)
Less: Cash and cash equivalents [1]	**201**	916	(715)
Debt, net of cash and cash equivalents [2]	**$ 2,117**	$ 3,475	$ (1,358)

(1) The decreases in total debt and cash and cash equivalents as of December 31, 2018, as compared to December 31, 2017, primarily relates to the repayment of the 2016 term loan in April 2018 and replacement with a new 2018 revolving credit facility as well as the repurchase of $900 million of certain of our senior notes.

(2) Debt, net of cash and cash equivalents is a non-GAAP financial measure of a company's ability to repay its debt if it was all due today.

- Net cash used in financing activities for the year ended December 31, 2018 was $2,297 million, compared to net cash used in financing activities of $352 million for the same period in 2017.
- In January 2018, we paid $27 million for a preferred stock dividend declared in the fourth quarter of 2017.
- In April 2018, we fully repaid our $1,191 million 2016 term loan and replaced it with the 2018 revolving credit facility with a $2.1 billion borrowing base. We recognized a loss on early extinguishment of debt of $8 million.
- In December 2018, upon closing of the Fayetteville Shale sale, a portion of the sale proceeds was used to complete a tender offer to repurchase $40 million of our 4.05% Senior Notes due January 2020, $787 million of our 4.10% Senior Notes due March 2022 and $73 million of our 4.95% Senior Notes due January 2025, reducing annual bond debt interest by approximately $39 million. We recognized a loss on early extinguishment of debt of $9 million, primarily related to the early retirement premiums.
- We also used a portion of the net proceeds from the Fayetteville Shale sale to repurchase 39 million shares of common stock for approximately $180 million.

We refer you to Note 8 to the consolidated financial statements included in this Annual Report for additional discussion of our outstanding debt and credit facilities.

Working Capital

- We had positive working capital of $110 million at December 31, 2018 primarily due to $201 million of cash and cash equivalents resulting from the net proceeds from the Fayetteville Shale sale and an increase in accounts receivable primarily related to the increase in commodity pricing in December 2018, as compared to December 2017.
- At December 31, 2017, we had positive working capital of $729 million primarily due to $916 million of cash and cash equivalents resulting from our fully-drawn 2016 term loan.

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, 2018, our material off-balance sheet arrangements and transactions include operating lease arrangements, $112 million in letters of credit outstanding against our 2018 revolving credit facility and $55 million in surety bonds issued as financial assurance on certain agreements. 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, 2018, were as follows:

Contractual Obligations

	Payments Due by Period					
(in millions)	**Total**	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
Transportation charges (1)	**$ 8,794**	$ 773	$ 1,408	$ 1,268	$ 1,744	$ 3,601
Debt	**2,342**	–	52	213	1,577	500
Interest on debt (2)	**1,161**	165	327	306	324	39
Operating leases (3)	**94**	38	41	11	3	1
Compression services (4)	**5**	3	2	–	–	–
Operating agreements	**42**	39	2	1	–	–
Purchase obligations	**52**	52	–	–	–	–
Other obligations (5)	**20**	12	8	–	–	–
	$ 12,510	$ 1,082	$ 1,840	$ 1,799	$ 3,648	$ 4,141

(1) As of December 31, 2018, we had commitments for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems. Of the total $8.8 billion, $3.1 billion related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. For further information, we refer you to "Operational Commitments and Contingencies" in Note 9 to the consolidated financial statements included in this Annual Report. This amount also included guarantee obligations of up to $463 million.

Included in the transportation charges above are $114 million (potentially due in less than one year) and $107 million (potentially due in one to two years) related to certain agreements that remain in the name of our marketing affiliate but are expected to be paid in full by Flywheel Energy Operating, LLC, the purchaser of the Fayetteville Shale assets. Of these amounts, we may be obligated to reimburse Flywheel Energy for a portion of volumetric shortfalls during 2019 and 2020 (up to $102 million) under these transportation agreements and have currently recorded an $88 million liability as of December 31, 2018.

Subsequent to December 31, 2018, we agreed to purchase firm transportation with pipelines in the Appalachian Basin starting in 2021 and running through 2032 totaling $357 million in total contractual commitments of which the seller has agreed to reimburse us for $133 million of this commitment.

(2) Interest payments on our senior notes were calculated utilizing the fixed rates associated with our fixed rate notes outstanding at December 31, 2018. Estimated interest payments on the revolving credit facility were excluded from this table since there was no outstanding balance at December 31, 2018 on our revolving credit facility. Senior note interest rates were based on our credit ratings as of December 31, 2018.

(3) Operating leases include costs for compressors, drilling rigs, pressure pumping equipment, aircraft, office space and other equipment under non-cancelable operating leases expiring through 2028.

(4) As of December 31, 2018, our E&P segment had commitments of approximately $4.9 million for compression services associated primarily with our Southwest Appalachia division.

(5) Our other significant contractual obligations include approximately $16 million for various information technology support and data subscription agreements.

Liabilities relating to uncertain tax positions are excluded from the table above as there is a high degree of uncertainty regarding the timing of future cash outflows related to such liabilities. Also excluded from the table above are future contributions to the pension and postretirement benefit plans. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 12 to the consolidated financial statements included in this Annual Report and "Critical Accounting Policies and Estimates" below for additional information.

We refer you to Note 8 to the consolidated financial statements included in this Annual Report for a discussion of the terms of our debt.

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

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

For further information, we refer you to "Litigation" and "Environmental Risk" in Note 9 to the consolidated financial statements included in this Annual Report.

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, 2018, we had a total of $1,755 million of costs excluded from our amortization base, all of which related to our properties in the United States. Inclusion of some or all of these costs in our properties in the United States in the future, without adding any associated reserves, could result in ceiling test impairments.

At December 31, 2018, the ceiling value of our reserves was calculated based upon the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.10 per MMBtu, for West Texas Intermediate oil of $65.56 per barrel and NGLs of $17.64 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, 2018. We had no derivative positions that were designated for hedge accounting as of December 31, 2018. Although no ceiling test impairment was recorded in 2018, future decreases in commodity prices, increases in costs and/or changes in the balance of costs excluded from amortization and other factors may result in impairments to our natural gas and oil properties.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.98 per MMBtu, West Texas Intermediate oil of $47.79 per barrel and NGLs of $14.41 per barrel, adjusted for market differentials, the 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, 2017. We had no derivative positions that were designated for hedge accounting as of December 31, 2017.

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

A decline in natural gas, oil and NGL prices used to calculate the discounted future net revenues of our reserves affects both the present value of cash flows and the quantity of reserves. In the past, nearly all of our reserve base was natural gas; therefore changes in oil and NGL prices used did not have as significant an impact as natural gas prices on cash flows and reserve quantities. With the sale of our Fayetteville Shale assets, our reserve base as of December 31, 2018, however, was approximately 68% natural gas, 29% NGLs and 3% oil. Therefore NGL and oil pricing will have a more significant impact on the cash flows and quantity of reserves going forward. Our standardized measure and reserve quantities as of December 31, 2018, were $6.0 billion and 11.9 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 costs 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 Director of Reserves, who is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Director of Reserves has more than 24 years of experience in petroleum engineering, including the estimation of natural gas and oil reserves, and holds a Bachelor of Science in Petroleum Engineering. Prior to joining us in 2018, our Director of Reserves served in various reservoir engineering roles for EP Energy Company, El Paso Corporation, Cabot Oil & Gas Corporation, Schlumberger and H.J. Gruy & Associates, and is a member of the Society of Petroleum Engineers. He reports to our Executive Vice President and Chief Operations Officer, who has more than 30 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. Prior to joining Southwestern in 2017, our Chief Operations Officer served in various engineering and leadership roles for EP Energy Corporation, El Paso Corporation, ARCO Oil and Gas Company, Burlington Resources and Peoples Energy Production, and is a member of the Society of Petroleum Engineers.

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 37 years and over 16 years of practical experience in petroleum geosciences and petroleum engineering, respectively; (2) have over 27 years and over 16 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 47% of our total reserve base as of December 31, 2018. 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 that include uncertainties. Any material change to these uncertainties 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, 2018, accounted for approximately 99% of our total proved reserves and approximately 100% of our proved undeveloped reserves. In the conduct of its audit, NSAI did not independently verify the data we provided to them with respect to ownership interests, natural gas, oil and NGL production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. NSAI has advised us that if, in the course of its audit, something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved any questions relating thereto or had independently verified such information or data. On January 16, 2019, NSAI issued its audit opinion as to the reasonableness of our reserve estimates for the year-ended December 31, 2018 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.

Assets and liabilities held for sale are subject to an assessment of fair value which includes many key valuation estimates, inputs and assumptions including but not limited to: production forecasts, pricing, basis differentials, operating and general and administrative expense forecasts, future development costs, discount rate determination and tax inputs. In the third quarter of 2018, we recognized certain assets and liabilities as held for sale related to the Fayetteville Shale sale requiring a comparison of their respective carrying cost and fair value less costs to sell. Our full cost pool assets were excluded from held for sale accounting treatment as they are governed by SEC Regulation S-X Rule 4-10. The fair value of our gathering assets to be sold was estimated using an estimated discounted cash flow model along with market assumptions. The assumptions used in the calculation of estimated discounted cash flows included future commodity prices, projections of estimated quantities of natural gas reserves, operating costs, projections of future rates of production, inflation factors and risk-adjusted discount rates. We believe the assumptions used were reasonable.

Under full cost accounting rules, sales of oil and gas properties, whether or not being amortized currently, shall be accounted for as a reduction of the full cost pool, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. For instance, a significant alteration would not ordinarily be expected to occur for sales involving less than 25 percent of the reserve quantities of a given cost center. Judgments are required around the determination of whether a divestment is deemed significant. Such judgments include an assessment of the of the reserve quantities sold as compared to total reserve quantities and other qualitative and quantitative assessments of the relationship between capitalized costs and proved reserves. We did not recognize a gain or loss on the sale of our oil and gas properties as the divestment was deemed not significant. Please refer to Note 3 – "Divestitures" to the consolidated financial statements included in this Annual Report for further detail.

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 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 2018, 2017 and 2016 we financially protected 77%, 70% and 28% of our natural gas production, respectively, with derivatives. The primary risks related to our derivative contracts are the volatility in market prices and basis differentials for our production. However, the market price risk is generally offset by the gain or loss recognized upon the related transaction that is financially protected.

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

As of December 31, 2018, none of our derivative contracts were designated for hedge accounting treatment. Changes in the fair value of unsettled derivatives that were not designated for hedge accounting treatment are recorded in gain (loss) on derivatives. See Note 5 to the consolidated financial statements included in this Annual Report for more information on our derivative position at December 31, 2018.

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

Pension and Other Postretirement Benefits

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation (see Note 12 to the consolidated financial statements included in this Annual Report 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, 2018 benefit obligation and periodic benefit cost to be recorded in 2019, the discount rate assumed is 4.35%. This compares to a discount rate of 3.75% and 4.20% for the benefit obligation and periodic benefit cost, respectively, recorded in 2018. For the 2019 periodic benefit cost, the expected return assumed remains 7.00%, from 2018.

Using the assumed rates discussed above, we recorded total benefit cost of $9 million in 2018 related to our pension and other postretirement benefit plans. Due to the significance of the discount rate and expected long-term rate of return, the following sensitivity analysis demonstrates the effect that a 0.5% change in those assumptions would have had on our 2018 pension expense:

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

As of December 31, 2018, we recognized a liability of $47 million, compared to $59 million at December 31, 2017, related to our pension and other postretirement benefit plans. During 2018, we also made cash payments totaling $13 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.

Our stock-based compensation is classified as either an equity award or a liability award in accordance with generally accepted accounting principles. The fair value of an equity-classified award is determined at the grant date and is amortized on a straight-line basis over the vesting life of the award. The fair-value of a liability-classified award is determined on a quarterly basis through the final vesting date and is amortized based on the current fair value of the award and the percentage of vesting period incurred to date.

New Accounting Standards

Refer to Note 1 to the consolidated financial statements included in 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, they 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 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 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 changes in law, the ability to obtain and maintain permits, any increase in severance or similar taxes, and legislation or regulation relating to hydraulic fracturing, climate and over-the-counter derivatives;

- the impact of the adverse outcome of any material litigation against us or judicial decisions that affect us or our industry generally;
- the effects of weather;
- increased competition;
- 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, 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, oil and certain NGLs along with interest rates. Our Board of Directors has approved risk management policies and procedures that utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risks is also overseen by our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our exposure to concentrations of credit risk consists primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our purchasers and their dispersion across geographic areas. However, for the years ended December 31, 2018 and 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.4% and 10.3%, respectively, of total natural gas, oil and NGL sales. A default on this account could have a material impact on the Company, but we do not believe that there is a material risk of an event of default. During the year ended December 31, 2016, no single third-party purchaser accounted for 10% or more of our consolidated revenues. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, oil and NGL production. See “Commodities Risk” below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

As of December 31, 2018, we had approximately $2.3 billion of outstanding senior notes with a weighted average interest rate of 6.68%, and no borrowings under our revolving credit facility. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates. At December 31, 2018, we had a long-term issuer credit rating of Ba2 by Moody’s, a long-term debt rating of BB by S&P and a long-term debt issuer default rating of BB by Fitch Ratings. Any upgrades or downgrades in our public debt ratings by Moody’s or S&P could decrease or increase our cost of funds, respectively.

	Expected Maturity Date						
(in millions except percentages)	2019	2020	2021	2022	2023	Thereafter	**Total**
Fixed rate payments [(1)]	$ –	$ 52	$ –	$ 213	$ –	$ 2,077	**$ 2,342**
Weighted average interest rate	–%	5.30%	–%	4.10%	–%	6.98%	**6.68%**

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

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 our production. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the production 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 5 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, 2018, 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, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Southwestern Energy Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Southwestern Energy Company and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 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, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PRICEWATERHOUSECOOPERS LLP

Houston, Texas
February 28, 2019

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except share/per share amounts)	For the years ended December 31, 2018	2017	2016
Operating Revenues:			
Gas sales	$ 1,998	$ 1,793	$ 1,273
Oil sales	196	102	69
NGL sales	352	206	92
Marketing	1,222	972	864
Gas gathering	89	126	138
Other	5	4	–
	3,862	3,203	2,436
Operating Costs and Expenses:			
Marketing purchases	1,229	976	864
Operating expenses	785	671	592
General and administrative expenses	209	233	247
Restructuring charges	39	–	73
Depreciation, depletion and amortization	560	504	436
Impairments	171	–	2,321
Gain on sale of assets, net	(17)	(6)	–
Taxes, other than income taxes	89	94	93
	3,065	2,472	4,626
Operating Income (Loss)	797	731	(2,190)
Interest Expense:			
Interest on debt	231	239	226
Other interest charges	8	9	14
Interest capitalized	(115)	(113)	(152)
	124	135	88
Gain (Loss) on Derivatives	(118)	422	(339)
Loss on Early Extinguishment of Debt	(17)	(70)	(51)
Other Income (Loss), Net	–	5	(4)
Income (Loss) Before Income Taxes	538	953	(2,672)
Provision (Benefit) for Income Taxes:			
Current	1	(22)	(7)
Deferred	–	(71)	(22)
	1	(93)	(29)
Net Income (Loss)	$ 537	$ 1,046	$ (2,643)
Mandatory convertible preferred stock dividend	–	108	108
Participating securities – mandatory convertible preferred stock	2	123	–
Net Income (Loss) Attributable to Common Stock	$ 535	$ 815	$ (2,751)
Earnings (Loss) Per Common Share:			
Basic	$ 0.93	$ 1.64	$ (6.32)
Diluted	$ 0.93	$ 1.63	$ (6.32)
Weighted Average Common Shares Outstanding:			
Basic	574,631,756	498,264,321	435,337,402
Diluted	576,642,808	500,804,297	435,337,402

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

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

(in millions)	For the years ended December 31, 2018 [1]	2017 [1]	2016
Net income (loss)	$ 537	$ 1,046	$ (2,643)
Change in value of pension and other postretirement liabilities:			
Amortization of prior service cost and net loss included in net periodic pension cost [2]	10	2	13
Net loss incurred in period [3]	(2)	(13)	(7)
Total change in value of pension and postretirement liabilities	8	(11)	6
Change in currency translation adjustment	–	6	3
Comprehensive income (loss)	$ 545	$ 1,041	$ (2,634)

(1) In 2018 and 2017, deferred tax activity incurred in other comprehensive income was offset by a valuation allowance.

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

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

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2018	December 31, 2017
	(in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 201	$ 916
Accounts receivable, net	581	428
Derivative assets	130	130
Other current assets	44	35
Total current assets	956	1,509
Natural gas and oil properties, using the full cost method, including $1,755 million as of December 31, 2018 and $1,817 million as of December 31, 2017 excluded from amortization	24,180	23,890
Gathering systems	38	1,315
Other	487	564
Less: Accumulated depreciation, depletion and amortization	(20,049)	(19,997)
Total property and equipment, net	4,656	5,772
Other long-term assets	185	240
TOTAL ASSETS	$ 5,797	$ 7,521
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 609	$ 533
Taxes payable	58	62
Interest payable	52	70
Dividends payable	–	27
Derivative liabilities	79	64
Other current liabilities	48	24
Total current liabilities	846	780
Long-term debt	2,318	4,391
Pension and other postretirement liabilities	46	58
Other long-term liabilities	225	313
Total long-term liabilities	2,589	4,762
Commitments and contingencies (Note 9)		
Equity:		
Common stock, $0.01 par value; 1,250,000,000 shares authorized; issued 585,407,107 shares as of December 31, 2018 and 512,134,311 as of December 31, 2017	6	5
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 6.25% Series B Mandatory Convertible, $1,000 per share liquidation preference, 1,725,000 shares issued and outstanding as of December 31, 2017, converted to common stock on January 12, 2018	–	–
Additional paid-in capital	4,715	4,698
Accumulated deficit	(2,142)	(2,679)
Accumulated other comprehensive loss	(36)	(44)
Common stock in treasury, 39,092,537 shares as of December 31, 2018 and 31,269 shares as of December 31, 2017	(181)	(1)
Total equity	2,362	1,979
TOTAL LIABILITIES AND EQUITY	$ 5,797	$ 7,521

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	For the twelve months ended December 31, 2018	2017	2016
Cash Flows From Operating Activities:			
Net income (loss)	$ 537	$ 1,046	$ (2,643)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	560	504	436
Amortization of debt issuance costs	8	9	14
Impairments	171	–	2,321
Deferred income taxes	–	(71)	(22)
(Gain) loss on derivatives, unsettled	24	(451)	373
Stock-based compensation	14	24	29
Gain on sale of assets, net	(17)	(6)	–
Restructuring charges	–	–	30
Loss on early extinguishment of debt	17	70	51
Other	(1)	13	8
Change in assets and liabilities:			
Accounts receivable	(153)	(65)	(30)
Accounts payable	65	48	(69)
Taxes payable	2	4	(5)
Interest payable	(10)	(2)	–
Other assets and liabilities	6	(26)	5
Net cash provided by operating activities	1,223	1,097	498
Cash Flows From Investing Activities:			
Capital investments	(1,290)	(1,268)	(593)
Proceeds from sale of property and equipment	1,643	10	430
Other	6	6	1
Net cash provided by (used in) investing activities	359	(1,252)	(162)
Cash Flows From Financing Activities:			
Payments on current portion of long-term debt	–	(328)	(1)
Payments on long-term debt	(2,095)	(1,139)	(1,175)
Payments on revolving credit facility	(1,983)	–	(3,268)
Borrowings under revolving credit facility	1,983	–	3,152
Payments on commercial paper	–	–	(242)
Borrowings under commercial paper	–	–	242
Change in bank drafts outstanding	17	9	(20)
Proceeds from issuance of long-term debt	–	1,150	1,191
Debt issuance costs	(9)	(24)	(17)
Proceeds from issuance of common stock	–	–	1,247
Purchase of treasury stock	(180)	–	–
Preferred stock dividend	(27)	(16)	(27)
Cash paid for tax withholding	(3)	(2)	(9)
Other	–	(2)	(1)
Net cash (used in) provided by financing activities	(2,297)	(352)	1,072
Increase (decrease) in cash and cash equivalents	(715)	(507)	1,408
Cash and cash equivalents at beginning of year	916	1,423	15
Cash and cash equivalents at end of year	$ 201	$ 916	$ 1,423

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Common Stock		Preferred Stock				Common Stock in Treasury		
	Shares Issued	Amount	Shares Issued	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Shares	Amount	Total
				(in millions, except share amounts)					
Balance at December 31, 2017	**512,134,311**	**$ 5**	**1,725,000**	**$ 4,698**	**$ (2,679)**	**$ (44)**	**31,269**	**$ (1)**	**$ 1,979**
Comprehensive income:									
Net income	–	–	–	–	208	–	–	–	208
Other comprehensive income	–	–	–	–	–	–	–	–	–
Total comprehensive income	–	–	–	–	–	–	–	–	208
Stock-based compensation	–	–	–	7	–	–	–	–	7
Conversion of preferred stock	74,998,614	1	(1,725,000)	(1)	–	–	–	–	–
Issuance of restricted stock	5,076	–	–	–	–	–	–	–	–
Cancellation of restricted stock	(160,168)	–	–	–	–	–	–	–	–
Performance units vested	214,866	–	–	–	–	–	–	–	–
Tax withholding – stock compensation	(338,808)	–	–	(1)	–	–	–	–	(1)
Balance at March 31, 2018	**586,853,891**	**$ 6**	**–**	**$ 4,703**	**$ (2,471)**	**$ (44)**	**31,269**	**$ (1)**	**$ 2,193**
Comprehensive income:									
Net income	–	–	–	–	51	–	–	–	51
Other comprehensive income	–	–	–	–	–	–	–	–	–
Total comprehensive income	–	–	–	–	–	–	–	–	51
Stock-based compensation	–	–	–	6	–	–	–	–	6
Issuance of restricted stock	307,743	–	–	–	–	–	–	–	–
Cancellation of restricted stock	(722,465)	–	–	–	–	–	–	–	–
Tax withholding – stock compensation	(9,068)	–	–	–	–	–	–	–	–
Balance at June 30, 2018	**586,430,101**	**$ 6**	**–**	**$ 4,709**	**$ (2,420)**	**$ (44)**	**31,269**	**$ (1)**	**$ 2,250**
Comprehensive loss:									
Net loss	–	–	–	–	(29)	–	–	–	(29)
Other comprehensive income	–	–	–	–	–	4	–	–	4
Total comprehensive loss	–	–	–	–	–	–	–	–	(25)
Stock-based compensation	–	–	–	5	–	–	–	–	5
Issuance of restricted stock	30,924	–	–	–	–	–	–	–	–
Cancellation of restricted stock	(248,342)	–	–	–	–	–	–	–	–
Treasury stock	–	–	–	–	–	–	4,829,011	(25)	(25)
Tax withholding – stock compensation	(17,521)	–	–	–	–	–	–	–	–
Balance at September 30, 2018	**586,195,162**	**$ 6**	**–**	**$ 4,714**	**$ (2,449)**	**$ (40)**	**4,860,280**	**$ (26)**	**$ 2,205**
Comprehensive income:									
Net income	–	–	–	–	307	–	–	–	307
Other comprehensive income	–	–	–	–	–	4	–	–	4
Total comprehensive income	–	–	–	–	–	–	–	–	311
Stock-based compensation	–	–	–	3	–	–	–	–	3
Conversion of preferred stock	–	–	–	–	–	–	–	–	–
Issuance of restricted stock	5,819	–	–	–	–	–	–	–	–
Cancellation of restricted stock	(673,147)	–	–	–	–	–	–	–	–
Treasury stock	–	–	–	–	–	–	34,232,257	(155)	(155)
Tax withholding – stock compensation	(120,727)	–	–	(2)	–	–	–	–	(2)
Balance at December 31, 2018	**585,407,107**	**$ 6**	**–**	**$ 4,715**	**$ (2,142)**	**$ (36)**	**39,092,537**	**$ (181)**	**$ 2,362**

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (CONTINUED)

	Common Stock		Preferred Stock	Additional	Retained Earnings	Accumulated Other	Common Stock in Treasury		
	Shares Issued	Amount	Shares Issued	Paid-In Capital	(Accumulated Deficit)[1]	Comprehensive Income (Loss)	Shares	Amount	**Total**
					(in millions, except share amounts)				
Balance at December 31, 2016	**495,248,369**	**$ 5**	**1,725,000**	**$ 4,677**	**$ (3,725)**	**$ (39)**	**31,269**	**$ (1)**	**$ 917**
Comprehensive income:									
Net income	–	–	–	–	351	–	–	–	**351**
Other comprehensive income	–	–	–	–	–	–	–	–	**–**
Total comprehensive income	–	–	–	–	–	–	–	–	**351**
Stock-based compensation	–	–	–	10	–	–	–	–	**10**
Preferred stock dividend	2,751,410	–	–	–	–	–	–	–	**–**
Issuance of restricted stock	4,549,122	–	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(113,185)	–	–	–	–	–	–	–	**–**
Performance units vested	121,208	–	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(59,455)	–	–	–	–	–	–	–	**–**
Balance at March 31, 2017	**502,497,469**	**$ 5**	**1,725,000**	**$ 4,687**	**$ (3,374)**	**$ (39)**	**31,269**	**$ (1)**	**$ 1,278**
Comprehensive income:									
Net income	–	–	–	–	284	–	–	–	**284**
Other comprehensive income	–	–	–	–	–	1	–	–	**1**
Total comprehensive income	–	–	–	–	–	–	–	–	**285**
Stock-based compensation	–	–	–	10	–	–	–	–	**10**
Preferred stock dividend	3,346,865	–	–	–	–	–	–	–	**–**
Issuance of restricted stock	353,803	–	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(303,135)	–	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(1,729)	–	–	–	–	–	–	–	**–**
Issuance of stock awards	72	–	–	–	–	–	–	–	**–**
Balance at June 30, 2017	**505,893,345**	**$ 5**	**1,725,000**	**$ 4,697**	**$ (3,090)**	**$ (38)**	**31,269**	**$ (1)**	**$ 1,573**
Comprehensive income:									
Net income	–	–	–	–	77	–	–	–	**77**
Other comprehensive income	–	–	–	–	–	1	–	–	**1**
Total comprehensive income	–	–	–	–	–	–	–	–	**78**
Stock-based compensation	–	–	–	9	–	–	–	–	**9**
Preferred stock dividend	3,346,738	–	–	(8)	–	–	–	–	**(8)**
Issuance of restricted stock	133,197	–	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(192,810)	–	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(37,811)	–	–	–	–	–	–	–	**–**
Balance at September 30, 2017	**509,142,659**	**$ 5**	**1,725,000**	**$ 4,698**	**$ (3,013)**	**$ (37)**	**31,269**	**$ (1)**	**$ 1,652**
Comprehensive income:									
Net income	–	–	–	–	334	–	–	–	**334**
Other comprehensive loss	–	–	–	–	–	(7)	–	–	**(7)**
Total comprehensive income	–	–	–	–	–	–	–	–	**327**
Stock-based compensation	–	–	–	9	–	–	–	–	**9**
Preferred stock dividend	3,346,703	–	–	(8)	–	–	–	–	**(8)**
Issuance of restricted stock	19,086	–	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(132,898)	–	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(241,239)	–	–	(1)	–	–	–	–	**(1)**
Balance at December 31, 2017	**512,134,311**	**$ 5**	**1,725,000**	**$ 4,698**	**$ (2,679)**	**$ (44)**	**31,269**	**$ (1)**	**$ 1,979**

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

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (CONTINUED)

	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 Shares	Common Stock in Treasury Amount	Total
	(in millions, except share amounts)								
Balance at December 31, 2015	**390,138,549**	**$ 4**	**1,725,000**	**$ 3,409**	**$ (1,082)**	**$ (48)**	**47,149**	**$ (1)**	**$ 2,282**
Comprehensive loss:									
Net loss	–	–	–	–	(1,132)	–	–	–	**(1,132)**
Other comprehensive income	–	–	–	–	–	4	–	–	**4**
Total comprehensive loss	–	–	–	–	–	–	–	–	**(1,128)**
Stock-based compensation	–	–	–	26	–	–	–	–	**26**
Preferred stock dividend	–	–	–	(27)	–	–	–	–	**(27)**
Issuance of restricted stock	84,165	–	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(24,333)	–	–	–	–	–	–	–	**–**
Treasury stock	–	–	–	–	–	–	(15,880)	–	**–**
Tax withholding – stock compensation	(524,703)	–	–	(5)	–	–	–	–	**(5)**
Balance at March 31, 2016	**389,673,678**	**$ 4**	**1,725,000**	**$ 3,403**	**$ (2,214)**	**$ (44)**	**31,269**	**$ (1)**	**$ 1,148**
Comprehensive loss:									
Net loss	–	–	–	–	(593)	–	–	–	**(593)**
Other comprehensive income	–	–	–	–	–	3	–	–	**3**
Total comprehensive loss	–	–	–	–	–	–	–	–	**(590)**
Stock-based compensation	–	–	–	16	–	–	–	–	**16**
Preferred stock dividend	3,024,737	–	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(64,762)	–	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(136,828)	–	–	(1)	–	–	–	–	**(1)**
Balance at June 30, 2016	**392,496,825**	**$ 4**	**1,725,000**	**$ 3,418**	**$ (2,807)**	**$ (41)**	**31,269**	**$ (1)**	**$ 573**
Comprehensive loss:									
Net loss	–	–	–	–	(708)	–	–	–	**(708)**
Other comprehensive income	–	–	–	–	–	2	–	–	**2**
Total comprehensive loss	–	–	–	–	–	–	–	–	**(706)**
Stock-based compensation	–	–	–	8	–	–	–	–	**8**
Preferred stock dividend	2,100,119	–	–	–	–	–	–	–	**–**
Issuance of common stock	98,900,000	1	–	1,246	–	–	–	–	**1,247**
Issuance of restricted stock	1,140	–	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(48,534)	–	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(3,179)	–	–	1	–	–	–	–	**1**
Balance at September 30, 2016	**493,446,371**	**$ 5**	**1,725,000**	**$ 4,673**	**$ (3,515)**	**$ (39)**	**31,269**	**$ (1)**	**$ 1,123**
Comprehensive loss:									
Net loss	–	–	–	–	(210)	–	–	–	**(210)**
Other comprehensive income	–	–	–	–	–	–	–	–	**–**
Total comprehensive loss	–	–	–	–	–	–	–	–	**(210)**
Stock-based compensation	–	–	–	8	–	–	–	–	**8**
Preferred stock dividend	2,041,533	–	–	–	–	–	–	–	**–**
Exercise of stock options	44,880	–	–	–	–	–	–	–	**–**
Issuance of restricted stock	2,167	–	–	–	–	–	–	–	**–**
Cancellation of restricted stock	(27,854)	–	–	–	–	–	–	–	**–**
Tax withholding – stock compensation	(264,542)	–	–	(4)	–	–	–	–	**(4)**
Issuance of stock awards	5,814	–	–	–	–	–	–	–	**–**
Balance at December 31, 2016	**495,248,369**	**$ 5**	**1,725,000**	**$ 4,677**	**$ (3,725)**	**$ (39)**	**31,269**	**$ (1)**	**$ 917**

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 marketing business and, until the Fayetteville Shale sale, its gathering business in Arkansas ("Midstream"). Southwestern conducts most of its business through subsidiaries and operates principally in two segments: E&P and Midstream. The Company also has drilling rigs located in Pennsylvania and West Virginia and provides oilfield products and services, principally serving its E&P operations.

E&P. Southwestern's primary business is the exploration for and production of natural gas, oil and NGLs, with ongoing operations focused on the development of unconventional natural gas and oil reservoirs located in Pennsylvania and West Virginia. 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."

Midstream. Southwestern's marketing activities capture opportunities that arise through the marketing and transportation of natural gas, oil and NGLs produced in its E&P operations.

In September 2018, the Company announced that it had signed an agreement to sell 100% of the equity in certain of its subsidiaries that owned and operated its Fayetteville Shale E&P and related midstream gathering assets for $1,865 million in cash, subject to customary closing adjustments ("Fayetteville Shale sale"). The sale closed December 3, 2018 resulting in net proceeds of approximately $1,650 million, following adjustments of $215 million primarily related to the net cash flows from the economic effective date to the closing date and certain other working capital adjustments, and is discussed in further detail in Note 3. The historical financial and operating results of the assets sold are included in these financial statements for the period of time during which we owned the assets.

Basis of Presentation

The consolidated financial statements included in this Annual Report present the Company's financial position, results of operations and cash flows for the periods presented in accordance with accounting principles generally accepted in the United States ("GAAP"). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company evaluates subsequent events through the date the financial statements are issued. Certain reclassifications have been made to the prior year financial statements to conform to the 2018 presentation. In the first quarter of 2018, the Company adopted ASU 2017-07 which required that all non-service costs related to the Company's pension plan be reclassified from general and administrative expenses to other income (loss), net for all periods presented. The adoption of ASU 2017-07 resulted in a reclassification of $5 million of curtailment and settlement costs from restructuring charges to other income (loss), net on the Company's consolidated statements of operations for the year ended December 31, 2016.

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. 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, 2018, 2017 and 2016 was insignificant.

Major Customers

The Company sells the vast majority of its E&P natural gas, oil and NGL production to third-party customers through its marketing subsidiary. For the years ended December 31, 2018 and 2017, two subsidiaries of Royal Dutch Shell Plc in aggregate accounted for approximately 10.4% and 10.3%, respectively, of total natural gas, oil and NGL sales. In 2016, no single customer accounted for 10% or greater of our total sales. The Company believes that the loss of a major customer would not have a material adverse effect on its ability to sell its natural gas, oil and NGL production because alternative purchasers are available.

Cash and Cash Equivalents

Cash and cash equivalents are defined by the Company as short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash. Management considers cash and cash equivalents to have minimal credit and market risk as the Company monitors the credit status of the financial institutions holding its cash and marketable securities. The following table presents a summary of cash and cash equivalents as of December 31, 2018 and December 31, 2017:

	For the years ended December 31,	
(in millions)	**2018**	2017
Cash	**$ 32**	$ 261
Marketable securities [1]	**169**	605
Other cash equivalents	**–**	50 [2]
Total	**$ 201**	$ 916

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

(2) Consists of time deposits.

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 $34 million and $17 million as of December 31, 2018 and 2017, 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, 2018, the Company had a total of $1,755 million of costs excluded from the amortization base, all of which related to its properties in the United States. Inclusion of some or all of these costs in the Company's United States properties in the future, without adding any associated reserves, could result in additional ceiling test impairments.

At December 31, 2018, using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.10 per MMBtu, West Texas Intermediate oil of $65.56 per barrel and NGLs of $17.64 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, 2018. The Company had no derivative positions that were designated for hedge accounting as of December 31, 2018.

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

The net book value of the Company's 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 and resulted in non-cash ceiling test impairments for the quarters ended those dates. Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $2.48 per MMBtu, West Texas Intermediate oil of $39.25 per barrel and NGLs of $6.74 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not results 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.

Gathering Systems. The Company's investment in gathering systems was primarily in a system serving its Fayetteville Shale operations in Arkansas. These assets were included in the Fayetteville Shale sale that closed in December 2018.

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

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

Impairment of Long-Lived Assets. The carrying value of non-full cost pool long-lived assets is evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable. In accordance with accounting guidance for Property, Plant and Equipment, assets held for sale are measured at the lower of carrying value or fair value less costs to sell. This accounting guidance does not apply to the Company's full cost pool assets, which are governed under SEC Regulation S-X 4-10, and thus were not classified as held for sale. Because the assets excluding the full cost pool met the criteria for held for sale accounting in the third quarter of 2018 due to their inclusion in the Fayetteville Shale sale, the Company determined the carrying value of certain non-full cost pool assets exceeded the fair value less costs to sell. As a result, an impairment charge of $160 million was recorded for the year ended December 31, 2018, of which $145 million related to midstream gathering assets held for sale and $15 million related to E&P assets held for sale. Separately, the Company recorded an $11 million impairment of other non-core assets that were not included in the Fayetteville Shale sale, for the year ended December 31, 2018.

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. The Company amortized $9 million of its marketing-related intangible asset in each of the years ended December 31, 2018, 2017 and 2016.

Income Taxes

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

The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties. The Company recognizes penalties and interest related to uncertain tax positions within the provision (benefit) for income taxes line in the accompanying consolidated statements of operations. Additional information regarding uncertain tax positions along with the impact of recent tax reform legislation can be found in Note 10.

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 derivative instruments to financially protect sales of natural gas, oil and NGLs. In addition, the Company uses interest rate swaps to manage exposure to unfavorable interest rate changes. Since the Company does not designate its derivatives for hedge accounting treatment, gains and losses resulting from the settlement of derivative contracts have been recognized in gain (loss) on derivatives in the consolidated statements of operations when the contracts expire and the related physical transactions of the underlying commodity are settled. Additionally, changes in the fair value of the unsettled portion of derivative contracts are also recognized in gain (loss) on derivatives in the consolidated statement of operations. See Note 5 – "Derivatives and Risk Management" and Note 7 – "Fair Value Measurements" for a discussion of the Company's hedging activities.

Earnings Per Share

Basic earnings per common share is computed by dividing net income (loss) attributable to common stock by the weighted average number of common shares outstanding during 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 and the assumed conversion of mandatory convertible preferred stock. An antidilutive impact is an increase in earnings per share or a reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities.

In 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 2018. The remaining proceeds of the offering were used for general corporate purposes.

In January 2015, the Company issued 34,500,000 depositary shares that entitled the holder to a proportional fractional interest in the rights and preferences of the mandatory convertible preferred stock, including conversion, dividend, liquidation and voting rights. The mandatory convertible preferred stock had the non-forfeitable right to participate on an as-converted basis at the conversion rate then in effect in any common stock dividends declared and, therefore, was considered a participating security. Accordingly, it has been included in the computation of basic and diluted earnings per share, pursuant to the two-class method. In the calculation of basic earnings per share attributable to common shareholders, earnings are allocated to participating securities based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. The Company's participating securities do not participate in undistributed net losses because they are not contractually obligated to do so. On January 12, 2018, all outstanding shares of mandatory convertible preferred stock were converted to 74,998,614 shares of the Company's common stock.

The Company declared dividends on its mandatory convertible preferred stock in the first, second and third quarters of 2017 that were settled partially in common stock for a total of 10,040,306 shares as well as each quarter in 2016 that were settled in common stock for a total of 9,917,799 shares.

In 2018, the Company repurchased 39,061,269 of its outstanding common stock for approximately $180 million at an average price of $4.63 per share.

The following table presents the computation of earnings per share for the years ended December 31, 2018, 2017 and 2016:

(in millions, except share/per share amounts)	For the years ended December 31, 2018	2017	2016
Net income (loss)	$ 537	$ 1,046	$ (2,643)
Mandatory convertible preferred stock dividend	–	108	108
Participating securities – mandatory convertible preferred stock	2	123	–
Net income (loss) attributable to common stock	$ 535	$ 815	$ (2,751)
Number of common shares:			
Weighted average outstanding	574,631,756	498,264,321	435,337,402
Issued upon assumed exercise of outstanding stock options	–	–	–
Effect of issuance of non-vested restricted common stock	698,103	1,061,056	–
Effect of issuance of non-vested performance units	1,312,949	1,478,920	–
Weighted average and potential dilutive outstanding	576,642,808	500,804,297	435,337,402
Earnings (loss) per common share:			
Basic	$ 0.93	$ 1.64	$ (6.32)
Diluted	$ 0.93	$ 1.63	$ (6.32)

The following table presents the common stock shares equivalent excluded from the calculation of diluted earnings per share for the years ended December 31, 2018, 2017 and 2016, as they would have had an antidilutive effect:

	For the years ended December 31, 2018	2017	2016
Unexercised stock options	5,909,082	116,717	3,692,697
Unvested share-based payment	3,692,794	5,361,849	959,233
Performance units	642,568	765,689	884,644
Mandatory convertible preferred stock	2,465,708	74,999,895	74,999,895
Total	12,710,152	81,244,150	80,536,469

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, 2018, 2017 and 2016:

(in millions)	For the years ended December 31, 2018	2017	2016
Cash paid during the year for interest, net of amounts capitalized	$ 135	$ 130	$ 75
Cash paid (received) during the year for income taxes	6	(5)	(15)
Increase (decrease) in noncash property additions	(42)	25	55

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. See Note 13 for a discussion of the Company's stock-based compensation.

Liability-Classified Awards

The fair value of a liability-classified award is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general and administrative expense or capitalized expense over the vesting period of the award. The Company's liability-classified performance unit awards include a performance condition based on cash flow per debt-adjusted share and two market conditions, one based on absolute total shareholder return and the other on relative total shareholder return as compared to a group of the Company's peers. The fair values of the two market conditions are calculated by Monte Carlo models on a quarterly basis.

Treasury Stock

In the third quarter of 2018, the Company announced its intention to repurchase up to $200 million of its outstanding common stock using a portion of the net proceeds from the Fayetteville Shale sale. As of December 31, 2018, approximately $180 million has been spent to repurchase 39,061,269 shares at an average price of $4.63 per share.

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, 2018 and 2017, 10,653 shares and 31,269 shares, respectively, were held in the Rabbi Trust and were accounted for as treasury stock. In 2018, 20,616 shares were released from the Rabbi Trust due to a reduction in our workforce. These shares are still held as treasury stock.

Foreign Currency Translation

The Company has designated the Canadian dollar as the functional currency for its 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 May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) (ASC 606, as subsequently amended). ASC 606 supersedes the revenue recognition requirements in topic 605, Revenue Recognition, and requires entities to recognize revenue when control of the promised goods or services is transferred to customers at an amount that reflects the consideration to which an entity expects to be entitled to in exchange for those goods or services. The Company adopted ASC 606 with an effective date of January 2018 using the modified retrospective approach. For public entities, ASC 606 became effective for fiscal years beginning after December 15, 2017. The adoption of this standard did not have a material effect on the Company's consolidated results of operations, financial position or cash flows. Additional disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flow from contracts with customers are available in Note 4 – "Revenue Recognition".

In March 2017, the FASB issued Accounting Standards Update No. 2017-07, Compensation - Retirement Benefits (Topic 715) ("Update 2017-07"), which provides additional guidance on the presentation of net benefit cost in the statement of operations and on the components eligible for capitalization in assets, and requires retrospective adoption. The guidance requires employers to disaggregate the service cost component from the other components of net benefit cost. The service cost component of the net periodic benefit cost shall be reported in the same line item as other compensation costs arising from services rendered by the employees during the period, except for amounts capitalized. All other components of net benefit cost shall be presented outside of a subtotal for income from operations. The Company adopted Update 2017-07 during the first quarter of 2018 resulting in no material impact to its consolidated statement of operations, financial position or cash flows. The non-service cost components of net periodic benefit cost are no longer presented as a component of general and administrative expense, but are now presented as a component of Other Income, Net for the years ended December 31, 2018, 2017 and 2016, and are disclosed in Note 12 – "Retirement and Employment Benefit Plans". The Company ceased capitalizing the non-service components of net periodic benefit costs prospectively as of the beginning of the first quarter of 2018.

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. The Company adopted this update during the first quarter of 2018 resulting in no impact on its consolidated statement of cash flows.

In February 2018, the FASB issued Accounting Standards Update No. 2018-02 that will amend the FASB Accounting Standards relating to tax effects in accumulated other comprehensive income (Topic 220) ("Updated 2018-02"). Update 2018-02 permits a company to reclassify the stranded income tax effects of the Tax Reform Act on items within accumulated comprehensive income to retained earnings. Although the amendments in Update 2018-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, the Company elected to early adopt the amendments of Update 2018-02 in the third quarter of 2018. The implementation did not have a material impact on the Company's consolidated statement of operations, financial position or cash flows due to the tax valuation allowance currently in place. Any adjustments required under this update were fully offset by valuation allowance adjustments for both continuing operations and accumulated other comprehensive income.

New Accounting Standards Not Yet Implemented in this Report

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases (Topic 842) ("Update 2016-02"), which seeks to increase transparency and comparability among organizations by, among other things, recognizing lease assets and lease liabilities on the balance sheet for leases classified as operating leases under previous GAAP and disclosing key information about leasing arrangements. The codification was amended through additional ASUs. Through the year ended December 31, 2018, the Company finalized its contract reviews for leases in effect at year-end, drafted its accounting policies, evaluated the new disclosure requirements and implemented a software solution. Upon adoption, the Company expects to recognize a discounted right-of-use asset and corresponding lease liability between $95 million and $115 million. The Company continues to review new contracts commenced during 2019 to determine the appropriate lease accounting treatment where applicable.

ASC 842 allows issuers to elect the date of initial application as either the beginning of the period of adoption or the beginning of the earliest comparative period presented in the financial statements. The Company plans to elect the period of adoption, January 1, 2019, as its initial application date which would not result in restating prior comparative periods. The adoption of this standard is not expected to materially change the Company's consolidated statement of operations or its consolidated statement of cash flows. The Form 10-Q filing for the quarter ended March 31, 2019 will include the full impact of ASC 842, along with the presentation of the discounted right-of-use asset and lease liability on the consolidated balance sheet.

(2) RESTRUCTURING CHARGES

The following table presents a summary of the restructuring charges included in Operating Income (Loss) for the years ended December 31, 2018, 2017 and 2016:

	For the years ended December 31,		
(in millions)	**2018** (1)	2017	2016 (2)
Reduction in workforce	**$ 23**	$ –	$ 73
Fayetteville Shale sale-related	**16**	–	–
Total restructuring charges	**$ 39**	$ –	$ 73

(1) Does not include a $4 million gain for the year ended December 31, 2018 related to curtailment of the other postretirement benefit plan presented in other income (loss), net on the consolidated statements of operations.

(2) Does not include a $5 million net loss for the year ended December 31, 2016 related to the curtailment and settlement of the pension and other postretirement benefit plans presented in other income (loss), net on the consolidated statements of operations.

The following table presents a summary of liabilities associated with the Company's restructuring activities at December 31, 2018, which are reflected in accounts payable on the consolidated balance sheet:

(in millions)	
Liability at December 31, 2017	$ –
Additions	39
Distributions	34
Liability at December 31, 2018	**$ 5**

Reduction in Workforce

In June 2018, the Company notified affected employees of a workforce reduction plan, which resulted primarily from a previously announced study of structural, process and organizational changes to enhance shareholder value and continues with respect to other aspects of the Company's business activities. Affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited. Although the plan was substantially implemented by the end of 2018, certain employees were retained into 2019. As of December 31, 2018, a liability of $1 million for severance payments has been accrued related to the 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. Severance payments and other separation costs related to restructuring were substantially completed by the end of 2016.

The following table presents a summary of the restructuring charges related to workforce reduction plans included in Operating Income (Loss) for the years ended December 31, 2018, 2017 and 2016:

	For the years ended December 31,		
(in millions)	**2018**	2017	2016 (1)
Severance (including payroll taxes)	$ 21	$ –	$ 44
Stock-based compensation	–	–	24
Other benefits	–	–	3
Outplacement services, other	2	–	2
Total reduction in workforce-related restructuring charges (2)	$ 23	$ –	$ 73

(1) Does not include $5 million non-cash charges related to the curtailment and settlement of the pension and other postretirement benefit plans for the year ended December 31, 2016 presented in other income (loss), net in the consolidated statements of operations. See Note 12 for additional details regarding the Company's retirement and employee benefit plans.

(2) Total restructuring charges were $21 million and $2 million for the Company's E&P and Midstream segments, respectively, for the year ended December 31, 2018 and $70 million and $3 million for the Company's E&P and Midstream segments, respectively, for the year ended December 31, 2016.

Fayetteville Shale Sale-Related

In December 2018, the Company closed on the sale of the equity in certain of its subsidiaries that owned and operated its Fayetteville Shale E&P and related midstream gathering assets in Arkansas. As part of this transaction, most employees associated with those assets became employees of the buyer although the employment of some was, or will be, terminated. All affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited. Additionally, a small number of employees have been retained to provide assistance through the divestiture transition period and will receive a similar severance package upon the deferred termination of their employment. As of December 31, 2018, a liability of $4 million for severance payments has been accrued related to remaining Fayetteville Shale sale-related employment terminations.

As a result of the Fayetteville Shale sale, the Company relocated certain employees and infrastructure to other areas. In addition to personnel-related costs, the Company has also incurred charges related to office consolidation and has recognized these costs as restructuring charges. The following table presents a summary of the restructuring charges related to Fayetteville Shale sale included in Operating Income (Loss) for the year ended December 31, 2018:

(in millions)	For the year ended December 31, 2018
Severance (including payroll taxes)	$ 12
Office consolidation	4
Total Fayetteville Shale sale-related charges (1) (2)	$ 16

(1) Total restructuring charges were $16 million for the Company's E&P segment for the year ended December 31, 2018.

(2) Does not include a $4 million gain for the year ended December 31, 2018 related to the curtailment of the other postretirement benefit plan presented in other income (loss), net on the consolidated statements of operations.

(3) DIVESTITURES

On August 30, 2018, the Company entered into an agreement with Flywheel Energy Operating, LLC to sell 100% of the equity in the Company's subsidiaries that owned and operated its Fayetteville Shale E&P and related midstream gathering assets for $1,865 million in cash, subject to customary closing adjustments, with an economic effective date of July 1, 2018. During the third quarter of 2018, the Company classified the non-full cost pool portion of these assets as held for sale and recorded an impairment charge of $160 million, of which $145 million related to midstream gathering assets held for sale and $15 million related to E&P assets held for sale.

On December 3, 2018, the Company closed on the Fayetteville Shale sale and received approximately $1,650 million, which included preliminary purchase price adjustments of approximately $215 million primarily related to the net cash flows from the economic effective date to the closing date. The Company allocated the sale proceeds to gain on sale for the non-full cost pool assets and to capitalized costs for the full cost pool assets based on the proportion of the estimated fair values of the underlying assets. The fair values of these assets was estimated primarily using an income approach. Consequently, the Company recognized a gain on the sale of non-full cost pool assets of $17 million and a reduction of $887 million to its full cost pool assets. As the sale did not involve a significant change in proved reserves or significantly alter the relationship between capitalized costs and proved reserves, the Company recognized no gain or loss related to the full cost pool assets sold.

As part of the Fayetteville Shale sale agreement, the Company entered into certain natural gas derivative positions which were subsequently novated to the buyer in conjunction with finalization of the sale. The unrealized fair value of these derivatives at the closing of the sale in December 2018 was a net liability of $151 million which was transferred to the buyer. The unrealized loss associated with the novated positions was offset by the gain that the Company recognized when the liability was transferred to the buyer. These offsetting amounts were recognized on the consolidated statements of operations in Gain on sale of assets, net. In addition, the Company paid $22 million in premiums for these novated derivatives which was recorded as a loss in Gain on sale of assets, net in 2018.

The Company retained certain contractual commitments related to firm transportation, with the buyer obligated to pay the transportation provider directly for these charges. As of December 31, 2018, approximately $221 million of these contractual commitments remain of which the Company will reimburse the buyer for certain of these potential obligations up to approximately $102 million through 2020 depending on the buyer's actual use, and has recorded an $88 million liability for the estimated future payments. The buyer will also assume future asset retirement obligations related to the operations sold.

From the proceeds received, $914 million was used to repurchase $900 million of the Company's outstanding senior notes, including premiums and $9 million in accrued interest paid, and $180 million was used to repurchase approximately 39 million shares of the Company's outstanding common stock as of December 31, 2018. The Company intends to use the remaining net proceeds from the sale to supplement Appalachian Basin development, return capital to shareholders and for general corporate purposes.

(4) REVENUE RECOGNITION

Effective January 1, 2018, the Company adopted Accounting Standards Codification ("ASC") 606, "Revenue from Contracts with Customers," using the modified retrospective method applied to those contracts which were not completed as of January 1, 2018. Under the modified retrospective method, The Company recognizes the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of retained earnings; however, no material adjustment was required as a result of adopting ASC 606. Results for reporting periods beginning on January 1, 2018 are presented under the new revenue standard. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. The Company performed an analysis of the impact of adopting ASC 606 across all revenue streams and did not identify any changes to its revenue recognition policies that would result in a material impact to its consolidated financial statements.

Revenues from Contracts with Customers

Natural gas and liquids. Natural gas, oil and NGL sales are recognized when control of the product is transferred to the customer at a designated delivery point. The pricing provisions of the Company's contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, quality of the product and prevailing supply and demand conditions in the geographic areas in which the Company operates. Under the Company's sales contracts, the delivery of each unit of natural gas, oil and NGLs represents a separate performance obligation, and revenue is recognized at the point in time when the performance obligations are fulfilled. There is no significant financing component to the Company's revenues as payment terms are typically within 30 to 60 days of control transfer. Furthermore, consideration from a customer corresponds directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognizes revenue in the amount to which the Company has a right to invoice and has not disclosed information regarding its remaining performance obligations.

The Company records revenue from its natural gas and liquids production in the amount of its net revenue interest in 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 as receivables and payables and not contract assets or contract liabilities as the imbalances are between the Company and other working interest owners, not the end customer.

Marketing. The Company, through its marketing affiliate, generally markets natural gas, oil and NGLs for its affiliated E&P companies as well as other joint owners who choose to market with Southwestern. In addition, the Company markets some products purchased from third parties. Marketing revenues for natural gas, oil and NGL sales are recognized when control of the product is transferred to the customer at a designated delivery point. The pricing provisions of the Company's contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, quality of the product and prevailing supply and demand conditions. Under the Company's marketing contracts, the delivery of each unit of natural gas, oil and NGLs represents a separate performance obligation, and revenue is recognized at the point in time when the performance obligations are fulfilled. Customers are invoiced and revenues are recorded each month as natural gas, oil and NGLs are delivered, and payment terms are typically within 30 to 60 days of control transfer. Furthermore, consideration from a customer corresponds directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognizes revenue in the amount to which the Company has a right to invoice and has not disclosed information regarding its remaining performance obligations.

Gas gathering. Prior to the Fayetteville Shale sale, the Company, through a subsidiary included in the Fayetteville Shale sale, gathered natural gas in Arkansas pursuant to a variety of contracts with customers, including an affiliated E&P company. The performance obligations for gas gathering services included delivery of each unit of natural gas to the designated delivery point, which may include treating of certain natural gas units to meet interstate pipeline specifications. Revenue was recognized at the point in time when performance obligations were fulfilled. Under the Company's gathering contracts, customers were invoiced and revenue was recognized each month based on the volume of natural gas transported and treated at a contractually agreed upon price per unit. Payment terms were typically within 30 to 60 days of completion of the performance obligations. Furthermore, consideration from a customer corresponded directly with the value to the customer of the Company's performance completed to date. As a result, the Company recognized revenue in the amount to which the Company had a right to invoice and therefore had not disclosed information regarding its remaining performance obligations. Any imbalances were settled on a monthly basis by cashing-out with the respective shipper. Accordingly, there were no contract assets or contract liabilities related to the Company's gas gathering revenues. The natural gas gathering operations in Arkansas were included in the Fayetteville Shale sale that closed in December 2018.

Disaggregation of Revenues

The Company presents a disaggregation of E&P revenues by product in the consolidated statements of operations net of intersegment revenues. The following table reconciles operating revenues as presented on the consolidated statements of operations to the operating revenues by segment:

(in millions)	E&P	Midstream	Intersegment Revenues	Total
Year ended December 31, 2018				
Gas sales	**$ 1,974**	**$ –**	**$ 24**	**$ 1,998**
Oil sales	**193**	**–**	**3**	**196**
NGL sales	**353**	**–**	**(1)**	**352**
Marketing	**–**	**3,497**	**(2,275)**	**1,222**
Gas gathering (1)	**–**	**248**	**(159)**	**89**
Other (2)	**5**	**–**	**–**	**5**
Total	**$ 2,525**	**$ 3,745**	**$ (2,408)**	**$ 3,862**
Year ended December 31, 2017				
Gas sales	$ 1,775	$ –	$ 18	$ 1,793
Oil sales	101	–	1	102
NGL sales	206	–	–	206
Marketing	–	2,867	(1,895)	972
Gas gathering	–	331	(205)	126
Other (2)	4	–	–	4
Total	$ 2,086	$ 3,198	$ (2,081)	$ 3,203
Year ended December 31, 2016				
Gas sales	$ 1,252	$ –	$ 21	$ 1,273
Oil sales	69	–	–	69
NGL sales	92	–	–	92
Marketing	–	2,191	(1,327)	864
Gas gathering	–	378	(240)	138
Total	$ 1,413	$ 2,569	$ (1,546)	$ 2,436

(1) The Company's gas gathering assets were divested in December 2018 as part of the Fayetteville Shale sale.

(2) Other E&P revenues consists primarily of water sales to third-party operators.

Associated E&P revenues are also disaggregated for analysis on a geographic basis by the core areas in which the Company operates, which are in Pennsylvania and West Virginia. Operations in northeast Pennsylvania are referred to as "Northeast Appalachia," operations in West Virginia and southwest Pennsylvania are referred to as "Southwest Appalachia." In December 2018, the Company sold 100% of its Fayetteville Shale assets. See Note 3 for more details.

	For the year ended December 31,		
(in millions)	**2018**	2017	2016
Northeast Appalachia	**$ 1,165**	$ 837	$ 470
Southwest Appalachia	**817**	498	259
Fayetteville Shale	**537**	743	675
Other	**6**	8	9
Total	**$ 2,525**	$ 2,086	$ 1,413

Receivables from Contracts with Customers

The following table reconciles the Company's receivables from contracts with customers to consolidated accounts receivable as presented on the consolidated balance sheet:

(in millions)	**December 31, 2018**	December 31, 2017
Receivables from contracts with customers	**$ 494**	$ 322
Other accounts receivable	**87**	106
Total accounts receivable	**$ 581**	$ 428

Amounts recognized against the Company's allowance for doubtful accounts related to receivables arising from contracts with customers were immaterial for the years ended December 31, 2018 and 2017. The Company has no contract assets or contract liabilities associated with its revenues from contracts with customers.

(5) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas, oil and NGLs which impacts the predictability of its cash flows related to the sale of those commodities. These risks are managed by the Company's use of certain derivative financial instruments. As of December 31, 2018, the Company's derivative financial instruments consisted of fixed price swaps, two-way costless collars, three-way costless collars, basis swaps, call options and interest rate swaps. During 2016, the Company settled all of its purchased put options. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps	If the Company sells a fixed price swap, the Company receives a fixed price for the contract and pays a floating market to the counterparty. If the Company purchases a fixed price swap, the Company receives a floating market price for the contract and pays a fixed price to the counterparty.
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. If the Company sells a basis swap, 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. If the Company purchases a basis swap, the Company pays the counterparty if the price differential is greater than the state terms of the contract and receives a payment from the counterparty if the price differential is less than the stated terms of the contract.
Call options	The Company purchases and sells call options in exchange for a premium. If the Company purchases a call option, the Company receives from the counterparty the excess (if any) of the market price over the strike price of the call option at the time of settlement, but if the market price is below the call's strike price, no payment is due from either party. If the Company sells a call option, the Company pays the counterparty the excess (if any) of the market price over the strike price at the time of settlement, but if the market price is 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 chooses counterparties for its derivative instruments that it believes are creditworthy at the time the transactions are entered into, and the Company actively monitors the credit ratings and credit default swap rates of these counterparties where applicable. However, there can be no assurance that a counterparty will be able to meet its obligations to the Company. The Company presents its derivative positions on a gross basis and does not net the asset and liability positions where counterparty netting arrangements contain provisions for net settlement.

As part of the Fayetteville Shale sale agreement, the Company entered into certain natural gas derivative positions which were subsequently novated to the buyer in conjunction with finalization of the sale. The unrealized fair value of these derivatives at the closing of the sale in December 2018 was a net liability of $151 million which was transferred to the buyer. The unrealized loss associated with the novated positions was offset by the gain that the Company recognized when the liability was transferred to the buyer. These offsetting amounts were recognized on the consolidated statements of operations in Gain on sale of assets, net. In addition, the Company paid $22 million in premiums for these novated derivatives which was recorded as a loss in Gain on sale of assets, net in 2018. The derivatives that were novated to the buyer are not included in the tables below.

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, the weighted average contract prices and the fair value by expected maturity dates as of December 31, 2018:

Financial Protection on Production

		Weighted Average Price per MMBtu					
	Volume *(Bcf)*	Swaps	Sold Puts	Purchased Puts	Sold Calls	Basis Differential	Fair value at December 31, 2018 *($ in millions)*
Natural Gas							
2019							
Fixed price swaps	220	$ 2.93	$ –	$ –	$ –	$ –	$ 23
Two-way costless collars	53	–	–	2.80	2.98	–	4
Three-way costless collars	170	–	2.48	2.90	3.28	–	8
Total	443						$ 35
2020							
Fixed price swaps	24	$ 2.88	$ –	$ –	$ –	$ –	$ 5
Three-way costless collars	84	–	2.40	2.73	3.03	–	–
Total	108						$ 5
2021							
Three-way costless collars	37	$ –	$ 2.35	$ 2.60	$ 2.93	$ –	$ (1)
Basis swaps							
2019	107	$ –	$ –	$ –	$ –	$ (0.29)	$ (10)
2020	59	–	–	–	–	(0.44)	(1)
Total	166						$ (11)

	Volume (MBbls)	Weighted Average Price per Bbl: Swaps	Purchased Puts	Sold Calls	Fair value at December 31, 2018 ($ in millions)
Oil					
2019					
Fixed price swaps [(1)]	346	$ 68.74	$ –	$ –	$ 7
Two-way costless collars	329	–	65.00	72.30	6
Total	675				$ 13
2020					
Fixed price swaps	366	$ 65.68	$ –	$ –	$ 6
Two-way costless collars	366	–	60.00	69.80	4
Total	732				$ 10
Propane					
2019					
Fixed price swaps	1,689	$ 33.12	$ –	$ –	$ 11
Ethane					
2019					
Fixed price swaps	3,687	$ 13.90	$ –	$ –	$ 4
2020					
Fixed price swaps	732	$ 13.49	$ –	$ –	$ 1

(1) Includes 274 MBbls of purchased fixed price oil swaps hedged at $69.10 per barrel with a fair value of ($6) million and 620 MBbls of sold fixed price oil swaps hedged at $68.90 with a fair value of $13 million.

Other Derivative Contracts

	Volume (Bcf)	Weighted Average Strike Price per MMBtu	Fair value at December 31, 2018 ($ in millions)
Purchased Call Options – Natural Gas			
2020	68	$ 3.63	$ 4
2021	57	3.52	2
Total	125		$ 6
Sold Call Options – Natural Gas			
2019	52	$ 3.50	$ (3)
2020	137	3.39	(12)
2021	114	3.33	(7)
Total	303		$ (22)

	Volume (MBbls)	Weighted Average Strike Price per Bbl	Fair Value at December 31, 2018 ($ in millions)
Sold Call Options – Oil			
2019	270	$ 65.00	$ –

	Volume (Bcf)	Weighted Average Strike Price per MMBtu	Basis Differential	Fair Value at December 31, 2018 ($ in millions)
Storage [(1)]				
2019				
Fixed price swaps	0.8	$ 3.03	$ –	$ –
Basis swaps	0.8	–	(0.44)	–
Total				$ –

(1) The Company has entered into certain derivatives to protect the value of volumes of natural gas injected into a storage facility that will be withdrawn at a later date.

At December 31, 2018, the net fair value of the Company's financial instruments related to commodities was a $51 million asset. The net fair value of the Company's interest rate swaps was a $1 million asset as of December 31, 2018.

As of December 31, 2018, 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 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, 2018 and 2017:

Derivative Assets

	Balance Sheet Classification	Fair Value	
(in millions)		December 31, 2018	December 31, 2017
Derivatives not designated as hedging instruments:			
Fixed price swap – natural gas	Derivative assets	$ 32	$ 38
Fixed price swap – oil	Derivative assets	13	–
Fixed price swap – propane	Derivative assets	11	–
Fixed price swap – ethane	Derivative assets	7	–
Two-way costless collar – natural gas	Derivative assets	11	5
Two-way costless collar – oil	Derivative assets	6	–
Three-way costless collar – natural gas	Derivative assets	41	82
Basis swap – natural gas	Derivative assets	8	2
Purchased call option – natural gas	Derivative assets	–	3 (1)
Interest rate swap	Derivative assets	1	–
Fixed price swap – natural gas	Other long-term assets	6	18
Fixed price swap – oil	Other long-term assets	6	–
Fixed price swap – ethane	Other long-term assets	1	–
Two-way costless collar – oil	Other long-term assets	5	–
Three-way costless collar – natural gas	Other long-term assets	34	39
Basis swap – natural gas	Other long-term assets	3	–
Purchased call options – natural gas	Other long-term assets	6	–
Total derivative assets		$ 191	$ 187

Derivative Liabilities

	Balance Sheet Classification	Fair Value	
(in millions)		December 31, 2018	December 31, 2017
Derivatives not designated as hedging instruments:			
Purchased fixed price swap – oil	Derivative liabilities	$ 6	$ –
Fixed price swap – natural gas	Derivative liabilities	9	–
Fixed price swap – ethane	Derivative liabilities	3	–
Two-way costless collar – natural gas	Derivative liabilities	7	1
Three-way costless collar – natural gas	Derivative liabilities	33	36
Basis swap – natural gas	Derivative liabilities	18	23
Sold call option – natural gas	Derivative liabilities	3	3
Interest rate swap	Derivative liabilities	–	1
Fixed price swap – natural gas	Other long-term liabilities	1	1
Two-way costless collar – oil	Other long-term liabilities	1	–
Three-way costless collar – natural gas	Other long-term liabilities	35	30
Basis swap – natural gas	Other long-term liabilities	4	–
Sold call option – natural gas	Other long-term liabilities	19	15
Total derivative liabilities		$ 139	$ 110

(1) Includes $1 million in premiums paid related to certain natural gas call options recognized as a component of derivative assets within current assets on the consolidated balance sheet at December 31, 2017. As certain natural gas call options settled, the premium was amortized and recognized as a component of gain (loss) on derivatives on the consolidated statements of operations.

The following tables summarize the before-tax effect of the Company's derivative instruments on the consolidated statements of operations for the years ended December 31, 2018 and 2017:

Unsettled Gain (Loss) on Derivatives Recognized in Earnings

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Unsettled	For the years ended December 31, 2018	2017
		(in millions)	
Purchased fixed price swap – oil	Gain (Loss) on Derivatives	$ (6)	$ –
Fixed price swap – natural gas	Gain (Loss) on Derivatives	(27)	232
Fixed price swap – oil	Gain (Loss) on Derivatives	19	–
Fixed price swap – propane	Gain (Loss) on Derivatives	11	–
Fixed price swap – ethane	Gain (Loss) on Derivatives	5	–
Two-way costless collar – natural gas	Gain (Loss) on Derivatives	–	52
Two-way costless collar – oil	Gain (Loss) on Derivatives	10	–
Three-way costless collar – natural gas	Gain (Loss) on Derivatives	(48)	136
Basis swap – natural gas	Gain (Loss) on Derivatives	10	(36)
Purchased call option – natural gas	Gain (Loss) on Derivatives	4	2
Sold call option – natural gas	Gain (Loss) on Derivatives	(4)	63
Interest rate swap	Gain (Loss) on Derivatives	2	2
Total gain (loss) on unsettled derivatives		$ (24)	$ 451

Settled Gain (Loss) on Derivatives Recognized in Earnings [(1)]

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled	For the years ended December 31, 2018	2017
		(in millions)	
Fixed price swap – natural gas	Gain (Loss) on Derivatives	$ (32)	$ (9)
Fixed price swap – propane	Gain (Loss) on Derivatives	(6)	–
Fixed price swap – ethane	Gain (Loss) on Derivatives	(8)	–
Two-way costless collar – natural gas	Gain (Loss) on Derivatives	(1)	–
Three-way costless collar – natural gas	Gain (Loss) on Derivatives	(9)	(1)
Basis swap – natural gas	Gain (Loss) on Derivatives	(31)	(6)
Purchased call option – natural gas	Gain (Loss) on Derivatives	2 [(2)]	–
Sold call option – natural gas	Gain (Loss) on Derivatives	(7)	(11)[(3)]
Sold call option – oil	Gain (Loss) on Derivatives	(2)	–
Interest rate swap	Gain (Loss) on Derivatives	–	(2)
Total loss on settled derivatives		$ (94)	$ (29)
Total gain (loss) on derivatives		$ (118)	$ 422

(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) Includes $1 million amortization of premiums paid related to certain natural gas call options for the year ended December 31, 2018, which is included in gain (loss) on derivatives on the consolidated statement of operations.

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

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

The following tables detail the components of accumulated other comprehensive income (loss) and the related tax effects, for the year ended December 31, 2018:

	For the year ended December 31, 2018		
(in millions)	Pension and Other Postretirement	Foreign Currency	Total
Beginning balance, December 31, 2017	$ (30)	$ (14)	$ (44)
Other comprehensive (loss) before reclassifications	(2)	–	(2)
Amounts reclassified from other comprehensive income [(1)] [(2)]	10	–	10
Net current-period other comprehensive income	8	–	8
Ending balance, December 31, 2018	$ (22)	$ (14)	$ (36)

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

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

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from/to Accumulated Other Comprehensive Income	
		For the year ended December 31, 2018	
		(in millions)	
Pension and other postretirement:			
Amortization of prior service cost and net loss (1)	Other Income (Loss), Net	$	10
	Provision (benefit) for income taxes (2)		–
	Net income	$	10
Total reclassifications for the period	Net income	$	10

(1) See Note 12 for additional details regarding the Company's pension and other postretirement benefit plans.

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

(7) FAIR VALUE MEASUREMENTS

Assets and liabilities measured at fair value on a recurring basis

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2018 and 2017 were as follows:

	December 31, 2018				December 31, 2017			
(in millions)	Carrying Amount		Fair Value		Carrying Amount		Fair Value	
Cash and cash equivalents	$	201	$	201	$	916	$	916
2018 revolving credit facility due April 2023		–		–		–		–
2016 term loan facility due December 2020 (1) (2)		–		–		1,191		1,191
Senior notes (1)(3)		2,342		2,190		3,242		3,358
Derivative instruments, net		52		52		77 (4)		77 (4)

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

(2) In April 2018, the Company replaced its 2016 credit facility with a new 2018 credit facility and repaid the $1,191 million secured term loan balance in full.

(3) In December 2018, the Company repurchased $900 million of certain of its outstanding senior notes with a portion of the net proceeds from the Fayetteville Shale sale.

(4) Includes $1 million in premiums paid related to certain natural gas call options recognized as a component of derivative assets within current assets on the consolidated balance sheet.

The carrying values of cash and cash equivalents, including marketable securities, 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 market prices of the Company's senior notes. These instruments were previously classified as a Level 2 measurement but substantially all senior notes were updated to a Level 1 in the second quarter of 2018 as the market activity of the Company's debt has resulted in timely quoted prices. The 4.05% Senior Notes due January 2020 remain a Level 2 measurement due to relative market inactivity.

The carrying values of the borrowings under the Company's revolving credit facility (to the extent utilized) and previous term loan facility approximate fair value because the interest rate is variable and reflective of market rates. The Company considers the fair value of its revolving credit facility to be a Level 1 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 for natural gas and oil derivatives and Oil Price Information Services ("OPIS") for ethane and propane derivatives. The Company utilizes 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, 2018 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 call options, two-way costless collars and three-way costless collars (Level 2) 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 and OPIS futures index, interest rates, volatility and credit worthiness. The Company's basis swaps (Level 2) are estimated using third-party calculations based upon forward commodity price curves. These instruments were previously classified as a Level 3 measurement in the fair value hierarchy but were updated to a Level 2 measurement in the second quarter of 2018 as a result of the Company's ability to derive volatility inputs and forward commodity price curves from directly observable sources.

Inputs to the Black-Scholes model, including the volatility input 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:

	December 31, 2018			
	Fair Value Measurements Using:			
(in millions)	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Assets				
Fixed price swap – natural gas	$ –	$ 38	$ –	$ 38
Fixed price swap – oil	–	19	–	19
Fixed price swap – propane	–	11	–	11
Fixed price swap – ethane	–	8	–	8
Two-way costless collar – natural gas	–	11	–	11
Two-way costless collar – oil	–	11	–	11
Three-way costless collar – natural gas	–	75	–	75
Basis swap – natural gas	–	11	–	11
Purchased call option – natural gas	–	6	–	6
Interest rate swap	–	1	–	1
Liabilities				
Purchased fixed price swap – oil	–	(6)	–	(6)
Fixed price swap – natural gas	–	(10)	–	(10)
Fixed price swap – ethane	–	(3)	–	(3)
Two-way costless collar – natural gas	–	(7)	–	(7)
Two-way costless collar – oil	–	(1)	–	(1)
Three-way costless collar – natural gas	–	(68)	–	(68)
Basis swap – natural gas	–	(22)	–	(22)
Sold call option – natural gas	–	(22)	–	(22)
Total	$ –	$ 52	$ –	$ 52

(in millions)	December 31, 2017 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
Assets				
Fixed price swap – natural gas	$ –	$ 56	$ –	$ 56
Two-way costless collar – natural gas	–	–	5	5
Three-way costless collar – natural gas	–	–	121	121
Purchased call option – natural gas [(1)]	–	–	3	3
Basis swap – natural gas	–	–	2	2
Liabilities				
Fixed price swap – natural gas	–	(1)	–	(1)
Two-way costless collar – natural gas	–	–	(1)	(1)
Three-way costless collar – natural gas	–	–	(66)	(66)
Basis swap – natural gas	–	–	(23)	(23)
Sold call option – natural gas	–	–	(18)	(18)
Interest rate swap	–	(1)	–	(1)
Total	$ –	$ 54	$ 23	$ 77

(1) Includes $1 million in premiums paid related to certain natural gas call options recognized as a component of derivative assets within current assets on the consolidated balance sheets at December 31, 2017.

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, 2018 and 2017. 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 consisted of net derivatives valued using pricing models incorporating assumptions that, in the Company's judgment, reflected reasonable assumptions a marketplace participant would have used as of December 31, 2018 and 2017.

(in millions)	For the years ended December 31, 2018	2017
Balance at beginning of year	**$ 22**	$ (195)
Total gains (losses):		
Included in earnings	**(17)**	199
Settlements [(1)]	**1**	18
Transfers into/out of Level 3 [(2)]	**(6)**	–
Balance at end of period	**$ –**	$ 22
Change in gains (losses) included in earnings relating to derivatives still held as of December 31	**$ –**	$ 217

(1) Includes $1 million and $5 million amortization of premiums paid related to certain natural gas call options for the years ended December 31, 2018 and 2017, respectively.

(2) Commodity derivatives previously presented as Level 3 were transferred to Level 2 in the second quarter of 2018 as the Company moved from using proprietary volatility inputs and forward curves to more widely available published information, increasing market observability.

See Note 12 for a discussion of the fair value measurement of the Company's pension plan assets.

Assets and liabilities measured at fair value on a nonrecurring basis

As further discussed in Note 3, the Company's announcement of the Fayetteville Shale sale resulted in the reclassification of certain related assets and liabilities to held for sale on its balance sheet in the third quarter of 2018. Because the non-full cost pool assets met the criteria for held for sale accounting in the third quarter of 2018 due to their inclusion in the Fayetteville Shale sale, the Company determined the carrying value of certain non-full cost pool assets exceeded the carrying value less costs to sell. As a result, an impairment charge of $160 million was recorded for the year ended December 31, 2018, of which $145 million related to midstream gathering assets held for sale and $15 million related to E&P assets held for sale. Separately, the Company recorded an $11 million impairment of other non-core assets that were not included in the Fayetteville Shale sale, for the year ended December 31, 2018. The estimated fair value of the gathering assets was based on an estimated discounted cash flow model and market assumptions. The significant Level 3 assumptions used in the calculation of estimated discounted cash flows included in future rates of production, inflation factors and risk adjusted discount rates. These impairments are included in Net Income (Loss) from Operations in the accompanying consolidated statements of operations. On December 3, 2018, the Company closed on the Fayetteville Shale sale. Consequently, the

Company recognized a net gain on the sale of non-full cost pool assets of $17 million, which consisted of a gain on the Midstream segment of $35 million and a loss on the E&P segment of $18 million.

(8) DEBT

The components of debt as of December 31, 2018 and 2017 consisted of the following:

	December 31, 2018			
(in millions)	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	Total
Variable rate (3.920% at December 31, 2018) 2018 revolving credit facility, due April 2023	$ –	$ – [1]	$ –	$ –
4.05% Senior Notes due January 2020 [2] [3]	52	–	–	52
4.10% Senior Notes due March 2022 [3]	213	(1)	–	212
4.95% Senior Notes due January 2025 [2] [3]	927	(7)	(1)	919
7.50 % Senior Notes due April 2026	650	(8)	–	642
7.75 % Senior Notes due October 2027	500	(7)	–	493
Total debt	$ 2,342	$ (23)	$ (1)	$ 2,318

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

(1) Unamortized issuance expense of $11 million associated with the 2018 revolving credit facility is classified as other long-term assets on the consolidated balance sheets and includes approximately $4 million in unamortized issuance expense associated with the Company's previous 2016 term loan facility.

(2) In February and June 2016, Moody's and S&P downgraded certain senior notes, which increased the interest rates by 175 basis points effective July 2016. As a result of the downgrades, interest rates increased to 5.80% for the 2020 Notes and 6.70% for the 2025 Notes. In April and May 2018, S&P and Moody's upgraded certain senior notes. As a result of these upgrades, interest rates decreased to 5.30% for the 2020 Notes and 6.20% for the 2025 Notes effective July 2018. The first coupon payment to the bondholders at the lower interest rate was paid in January 2019.

(3) In December 2018, the Company repurchased $40 million of its 4.05% senior notes due January 2020, $787 million of its 4.10% senior notes due March 2022 and $73 million of its 4.95% senior notes due January 2025.

(4) In April 2018, the Company repaid the $1,191 million secured term loan balance with cash on hand and borrowings under the 2018 credit facility.

The following is a summary of scheduled debt maturities by year as of December 31, 2018:

	(in millions)
2019	$ –
2020	52
2021	–
2022	213
2023	–
Thereafter	2,077
	$ 2,342

Credit Facilities

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, remained unsecured and the maturity remained December 2018. On April 26, 2018 the Company replaced its 2016 credit facility with the 2018 credit facility and terminated the 2013 credit facility.

2016 Credit Facility

In June 2016, the Company reduced its existing $2.0 billion unsecured revolving credit facility, entered into in December 2013, to $66 million and entered into a new credit agreement for $1,934 million, consisting of a $1,191 million secured term loan and a new $743 million unsecured revolving credit facility, maturing in December 2020.

Concurrent with the closing of the new 2018 credit facility agreement on April 26, 2018, the Company repaid the $1,191 million secured term loan balance and recognized a loss on early debt extinguishment of $8 million on the consolidated income statement related to the unamortized issuance expense. In addition, approximately $4 million of unamortized issuance expense associated with the closed $743 million revolving credit facility was carried forward into the unamortized issuance expenses of the 2018 credit facility. At December 31, 2017, the $1,191 million secured term loan was fully drawn, there were no borrowings under the revolving credit facility, but $323 million in letters of credit was outstanding under the 2016 revolving credit facility.

2018 Revolving Credit Facility

In April 2018, as part of the Company's strategic effort to simplify the capital structure, increase financial flexibility and reduce costs, the Company replaced its 2016 credit facility (which consisted of a $1,191 million secured term loan and an unsecured $743 million revolving credit facility) with a new revolving credit facility (the "2018 credit facility"). The 2018 credit facility has an aggregate maximum revolving credit amount of $3.5 billion, and at December 31, 2018, had a current borrowing base of $2.1 billion with a current aggregate commitment of $2.0 billion. The borrowing base is subject to redetermination twice a year in April and October. The 2018 credit facility matures in April 2023 and is secured by substantially all of the assets owned by the Company and its subsidiaries.

Loans under the 2018 credit facility 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 for such interest period plus the applicable margin (as those terms are defined in the 2018 credit facility documentation). The applicable margin for Eurodollar loans under the 2018 credit facility ranges from 1.50% to 2.50% based on the Company's utilization of the borrowing base under the 2018 credit facility. Alternate base rate loans bear interest at the alternate base rate plus the applicable margin. The applicable margin for alternate base rate loans under the 2018 credit facility ranges from 0.50% to 1.50% based on the Company's utilization of the borrowing base under the 2018 credit facility.

The 2018 credit facility contains customary representations and warranties and contains covenants including, among others, the following:

- a prohibition against incurring debt, subject to permitted exceptions;
- a restriction on creating liens on assets, subject to permitted exceptions;
- restrictions on mergers and asset dispositions;
- restrictions on use of proceeds, investments, transactions with affiliates, or change of principal business; and
- maintenance of the following financial covenants, commencing with the fiscal quarter ended June 30, 2018:
    1. Minimum current ratio of no less than 1.00 to 1.00, whereby current ratio is defined as the Company's consolidated current assets (including unused commitments under the credit agreement, but excluding non-cash derivative assets) to consolidated current liabilities (excluding non-cash derivative obligations and current maturities of long-term debt).

2. Maximum total net leverage ratio of no less than (i) with respect to each fiscal quarter ending during the period from June 30, 2018 through March 31, 2019, 4.50 to 1.00, (ii) with respect to each fiscal quarter ending during the period from June 30, 2019 through March 31, 2020, 4.25 to 1.00, and (iii) with respect to each fiscal quarter ending on or after June 30, 2020, 4.00 to 1.00. Total net leverage ratio is defined as total debt less cash on hand (up to the lesser of 10% of credit limit or $150 million) divided by consolidated EBITDAX for the last four consecutive quarters. EBITDAX, as defined in the Company's 2018 credit agreement, excludes the effects of interest expense, depreciation, depletion and amortization, income tax, 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.

The 2018 credit facility contains customary events of default that include, among other things, the failure to comply with the financial covenants described above, non-payment of principal, interest or fees, violation of covenants, inaccuracy of representations and warranties, bankruptcy and insolvency events, material judgments and cross-defaults to material indebtedness. If an event of default occurs and is continuing, all amounts outstanding under the 2018 credit facility may become immediately due and payable. In the fourth quarter of 2018, the Company entered into hedges that, when added to existing hedges including hedges put in place as part of the Fayetteville Shale sale that the buyer was obligated to assume at closing of that sale, exceeded a cap on hedges for the month of December 2018 under a covenant under the Company's credit agreement. In conjunction with the closing, the buyer paid for the settlement of the December 2018 hedges it was to assume. The lenders have subsequently waived all matters associated with this default. Otherwise, as of December 31, 2018, the Company was in compliance with all of the remaining covenants of this credit agreement in all material respects.

Each United States domestic subsidiary of the Company for which the Company owns 100% of its equity guarantees the 2018 credit facility. Pursuant to requirements under the indentures governing the Company's senior notes, each subsidiary that became a guarantor of the 2018 credit facility also became a guarantor of each of the Company's senior notes. See Note 15 for the Company's Condensed Consolidated Financial Information, presented in accordance with Rule 3-10 of Regulation S-X. At the closing of the Fayetteville Shale sale, its subsidiaries being sold were released from these guarantees.

As of December 31, 2018, the Company had $112 million in letters of credit and no borrowings outstanding under the 2018 revolving credit facility.

Senior Notes

In January 2015, the Company completed a public offering of $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 2020 Notes, the "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, which increased the interest rates by 175 basis points effective July 2016. As a result of these downgrades, interest rates increased to 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 6.05% and 6.95%, respectively. The first coupon payment to the bondholders at the higher interest rates was paid in January 2017. S&P and Moody's upgraded the Notes in April and May 2018, respectively. As a result of these upgrades, interest rates decreased to 5.30% for the 2020 Notes and 6.20% for the 2025 Notes effective July 2018. The first coupon payment to bondholders at the lower interest rates will be paid in January 2019.

During the first half of 2017, the Company redeemed or repurchased (i) the remaining $38 million principal amount of its outstanding 3.30% Senior Notes due 2018, (ii) the remaining $212 million principal amount of its outstanding 7.50% Senior Notes due February 2018 and (iii) the remaining $26 million principal amount of its outstanding 7.15% Senior Notes due June 2018, and recognized an $11 million loss on the extinguishment of debt.

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

As discussed in Note 3 above, in December 2018, the Company closed on the Fayetteville Shale sale and used a portion of the proceeds to repurchase $40 million of its 4.05% Senior Notes due January 2020, $787 million of its 4.10% Senior

Notes due March 2022 and $73 million of its 4.95% Senior Notes due January 2025. The Company recognized a loss on extinguishment of debt of $9 million, which included $2 million of premiums paid.

(9) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of December 31, 2018, 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 $8.8 billion, $3.1 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 $463 million of that amount. As of December 31, 2018, future payments under non-cancelable firm transportation and gathering agreements are as follows:

	Payments Due by Period					
(in millions)	**Total**	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
Infrastructure currently in service	**$ 5,715**	$ 637	$ 1,060	$ 876	$ 1,123	$ 2,019
Pending regulatory approval and/or construction (1)	**3,079**	136	348	392	621	1,582
Total transportation charges	**$ 8,794**	$ 773	$ 1,408	$ 1,268	$ 1,744	$ 3,601

(1) Based on the estimated in-service dates as of December 31, 2018.

In December 2018, the Company closed on the Fayetteville Shale sale. The Company retained certain contractual commitments related to firm transportation, with the buyer obligated to pay the transportation provider directly for these charges. As of December 31, 2018, approximately $221 million of these contractual commitments remain of which the Company will reimburse the buyer for certain of these potential obligations up to approximately $102 million through 2020 depending on the buyer's actual use, and has recorded an $88 million liability for the estimated future payments. The buyer will also assume future asset retirement obligations related to the operations sold.

The Company leases pressure pumping equipment for its E&P operations under a single lease that expires in 2021. The current aggregate annual payment under this lease is approximately $7 million. The Company has seven leases for drilling rigs for its E&P operations that expire through 2024 with a current aggregate annual payment of approximately $13 million. The lease payments for the pressure pumping equipment, as well as other operating expenses for the Company's drilling operations, are capitalized to natural gas and oil properties and are partially offset by billings to third-party working interest owners.

The Company leases compressors, aircraft, vehicles, office space and equipment under non-cancelable operating leases expiring through 2028. As of December 31, 2018, future minimum payments under these non-cancelable leases accounted for as operating leases are approximately $38 million in 2019, $28 million in 2020, $14 million in 2021, $6 million in 2022, $5 million in 2023 and $4 million thereafter.

The Company also has commitments for compression services and rentals related to its E&P segment. As of December 31, 2018, future minimum payments under these non-cancelable agreements are approximately $3 million in 2019 and $1 million in each of 2020 and 2021.

Subsequent to December 31, 2018, the Company agreed to purchase firm transportation with pipelines in the Appalachian Basin starting in 2021 and running through 2032 totaling $357 million in total contractual commitments of which the seller has agreed to reimburse $133 million of this commitment.

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, results of operations or cash flows of the Company.

Litigation

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

Arkansas Royalty Litigation

The Company has been a defendant in three certified class actions alleging that the Company underpaid lessors of lands in Arkansas by deducting from royalty payments costs for gathering, transportation and compression of natural gas in excess of what is permitted by the relevant leases. Two of these class actions were filed in Arkansas state courts and the third in the United States District court for the Eastern District of Arkansas. The Company denied liability in all three cases. Under the agreement for the sale of the Company's properties in the Fayetteville Shale, the Company retained responsibility for these class actions.

In June 2017, the jury returned a verdict in favor of the Company on all counts in Smith v. SEECO, Inc. et al., the class action in the federal court, whose plaintiff class comprises the vast majority of the lessors in these cases. The plaintiff had asserted claims for, among other things, breach of contract, fraud, civil conspiracy, unjust enrichment and violation of certain Arkansas statutes. Following the verdict, the court entered judgment in favor of the Company on all claims. The trial court denied the plaintiff's motion for a new trial, and the plaintiff appealed to the United States Court of Appeals for the Eighth Circuit. Independent of the plaintiff's appeal, several different parties sought to intervene in the Smith case prior to or shortly after trial, and have appealed the trial court's order denying their request to intervene. Oral argument occurred in January 2019. The Court of Appeals has not yet issued its decision.

In the second quarter of 2018, the company entered into an agreement to settle another of the class actions, which has been pending in the Circuit Court of Conway County, Arkansas under the caption *Snow, et al v. SEECO, Inc., et al*. The settlement received final approval by the court during the third quarter, and the deadline to appeal the order approving the settlement passed without any appeals filed. The amount of the settlement is reflected in the Company's consolidated statement of operations for 2018 and has been paid. The third class action was dismissed in the second quarter of 2018.

The *Smith* and the *Snow* cases cover all affected lessors, except a small percentage who opted out. Most of these have filed separate actions. The Company does not expect those cases to have a material adverse effect on the results of operations, financial position or cash flows of the Company. Additionally, it is not possible at this time to estimate the amount of any additional loss, or range of loss, that is reasonably possible.

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. The Company likewise obtains indemnification for future matters when it sells assets, although there is no assurance the buyer will be capable of performing those obligations. No material liabilities have been recognized in connection with these indemnifications.

(10) INCOME TAXES

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

(in millions)	2018	2017	2016
Current:			
Federal	$ (5)	$ (22)	$ (6)
State	6	–	(1)
	1	(22)	(7)
Deferred:			
Federal	–	(71)	(22)
State	–	–	–
	–	(71)	(22)
Provision (benefit) for income taxes	$ 1	$ (93)	$ (29)

The provision for income taxes was an effective rate of 0% in 2018, (10%) in 2017 and 1% in 2016. The Company's effective tax rate increased in 2018, as compared with 2017, primarily due to state income taxes resulting from the Fayetteville Shale sale and the impact of the Tax Cuts and Jobs Act ("Tax Reform Act") on the tax rate and alternative minimum taxes, as well as changes to the overall valuation allowance activity during 2018. The following reconciles the provision for income taxes included in the consolidated statements of operations with the provision which would result from application of the statutory federal tax rate to pre-tax financial income:

(in millions)	2018	2017	2016
Expected provision (benefit) at federal statutory rate	$ 113	$ 333	$ (935)
Increase (decrease) resulting from:			
State income taxes, net of federal income tax effect	13	16	(79)
Rate impacts due to tax reform	–	370	–
Changes to valuation allowance due to tax reform	–	(370)	–
AMT tax reform impact – valuation allowance release	–	(68)	–
Changes in uncertain tax positions	–	(5)	(19)
Change in valuation allowance	(121)	(364)	1,002
Removal of sequestration fee on AMT receivables	(5)	–	–
Other	1	(5)	2
Provision (benefit) for income taxes	$ 1	$ (93)	$ (29)

The 2018 tax accrual calculated under the estimated annual effective tax rate method reflects the Tax Reform Act changes that took effect January 1, 2018. The components of the Company's deferred tax balances as of December 31, 2018 and 2017 were as follows:

(in millions)	2018	2017
Deferred tax liabilities:		
Differences between book and tax basis of property	$ 226	$ 395
Derivative activity	12	19
Other	2	1
	240	415
Deferred tax assets:		
Accrued compensation	33	29
Accrued pension costs	10	14
Asset retirement obligations	15	41
Net operating loss carryforward	777	1,043
Other	14	20
	849	1,147
Valuation allowance	(609)	(732)
Net deferred tax liability	$ –	$ –

On December 22, 2017, the United States enacted the Tax Reform Act, which made significant changes to the U.S. federal income tax law affecting the Company. Major changes in this legislation applicable to the Company relate to the reduction in the corporate tax rate to 21%, repeal of the alternative minimum tax, interest deductibility and net operating loss carryforward limitations, changes to certain executive compensation and full expensing provisions related to business assets. Due to the tax valuation allowance currently in place, any adjustments required to deferred taxes as a result of the Tax Reform Act were fully offset by valuation allowance adjustments, and the Company continues to examine the impact of this legislation and future regulations.

As the Tax Reform Act repealed the corporate alternative minimum tax for tax years beginning on or after January 1, 2018 and provided for existing alternative minimum tax credit carryovers to be refunded beginning in 2018, the Company has approximately $68 million in refundable credits that are expected to be fully refunded between 2019 and 2021. Accordingly, in 2017 the valuation allowance in place prior to the Tax Reform Act related to these credits was released, and any credits remaining were reclassed to a receivable.

In February 2018, the FASB issued Accounting Standards Update No. 2018-02 (“Update 2018-02”) amending the FASB Accounting Standards relating to tax effects in accumulated other comprehensive income. In the first quarter of 2018, the Company elected to early adopt the amendments of Update 2018-02. The implementation did not have a material impact on the Company’s consolidated statements of operations, financial position or cash flows due to the tax valuation allowance currently in place. See Note 1 for more information regarding this update.

In 2018, the Company made state income tax payments of $6.3 million. In 2017, the Company received less than $1 million in state income tax refunds and received $4.2 million in federal income tax refunds. The Company’s net operating loss carryforward as of December 31, 2018 was $3.0 billion and $2.1 billion for federal and state reporting purposes, respectively, the majority of which will expire between 2035 and 2037. Additionally, the Company has an income tax net operating loss carryforward related to its Canadian operations of $29 million, with expiration dates of 2030 through 2038. The Company also had a statutory depletion carryforward of $13 million as of December 31, 2018.

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

The Company maintained its net deferred tax asset position at December 31, 2018 primarily due to the prior write-downs of the carrying value of natural gas and oil properties. The Company believes it is more likely than not that these deferred tax assets will not be realized and accordingly maintained our full valuation allowance to adjust the remaining deferred tax asset to zero for the year ended December 31, 2018. During 2018, the valuation allowance was reduced $123 million, $121 million as a component of income tax expense and $2 million as a reduction of equity. Management assesses available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. In management’s view, the cumulative loss incurred over the three-year period ending December 31, 2018, 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. It is reasonably possible that a release of the valuation allowance could occur as early as the first quarter of 2019 if the Company moves into a three-year pre-tax income position combined with other positive evidence of future taxable income.

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

(in millions)		
Valuation allowance as of December 31, 2017	$	732
Changes based on 2018 activity		(121)
Equity – pension benefits in OCI		(2)
Valuation allowance as of December 31, 2018	**$**	**609**

On March 30, 2016, the FASB modified its accounting policy on share-based payments (ASU 2016-09). Updates included tax impacts related to the treatment of excess tax benefits (“windfalls”) and deficiencies (“shortfalls”) were made and became effective on January 1, 2017. The Company had previously unrecognized tax “windfall” benefits of $149 million as of December 31, 2016, which were released in the first quarter of 2017. The recognition of previously unrecognized windfall tax benefits resulted in a net cumulative-effect adjustment of $59 million, which increased net deferred tax assets and the related income tax valuation allowance by the same amount as of the beginning of 2017. As of December 31, 2018, no unrecognized tax benefits exist related to share-based payments.

A tax position must meet certain thresholds for any of the benefit of the uncertain tax position to be recognized in the financial statements. As of December 31, 2018, the amount of unrecognized tax benefits related to alternative minimum tax was $7 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, 2018, the Company had accrued a liability of less than $1 million of interest related to this uncertain tax position. The Company recognizes penalties and interest related to uncertain tax positions in income tax expense.

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

(in millions)	2018	2017
Unrecognized tax benefits at beginning of period	$ 12	$ 17
Additions based on tax positions related to the current year	–	–
Additions to tax positions of prior years	–	–
Reductions to tax positions of prior years	(5)	(5)
Unrecognized tax benefits at end of period	$ 7	$ 12

The Internal Revenue Service is currently auditing the Company's federal income tax return for 2014. The income tax years 2014 to 2018 remain open to examination by the major taxing jurisdictions to which the Company is subject.

(11) ASSET RETIREMENT OBLIGATIONS

The following table summarizes the Company's 2018 and 2017 activity related to asset retirement obligations:

(in millions)	2018	2017
Asset retirement obligation at January 1	$ 165	$ 141
Accretion of discount	9	8
Obligations incurred	1	3
Obligations settled/removed [(1)]	(116)	(10)
Revisions of estimates	2	23
Asset retirement obligation at December 31	$ 61	$ 165
Current liability	6	12
Long-term liability	55	153
Asset retirement obligation at December 31	$ 61	$ 165

(1) Obligations settled/removed include $111 million related to asset divestitures in 2018, of which $107 million related to the Fayetteville Shale sale.

(12) RETIREMENT AND EMPLOYEE BENEFIT PLANS

401(k) Defined Contribution Plan

The Company has a 401(k) defined contribution plan covering eligible employees. The Company expensed $3 million, $3 million and $4 million of contribution expense in 2018, 2017 and 2016, respectively. Additionally, the Company capitalized $2 million of contributions in each of 2018, 2017 and 2016, 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 of the Company's employees are covered by the 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 June 2018, the Company notified affected employees of a workforce reduction plan, which resulted primarily from a previously announced study of structural, process and organizational changes to enhance shareholder value and continues with respect to other aspects of the Company's business activities. In December 2018, the Company closed on the sale of the equity in certain of its subsidiaries that owned and operated its Fayetteville Shale E&P and related midstream gathering assets in Arkansas. As part of this transaction, many employees associated with those assets were either transferred to the buyer or their employment was terminated. As a result of the restructurings, the Company recognized a curtailment on its pension and other postretirement benefit plans and recognized a non-cash gain of $4 million on its consolidated statements of operations. During the first half of 2019, the Company will recognize settlements related to these restructuring events, and the amounts may be material.

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, 2018 and 2017:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2018**	2017	**2018**	2017
Change in benefit obligations:				
Benefit obligation at January 1	**$ 143**	$ 117	**$ 17**	$ 13
Service cost	**10**	9	**2**	2
Interest cost	**5**	5	**1**	–
Participant contributions	**–**	–	**–**	–
Actuarial loss (gain)	**(14)**	21	**–**	3
Benefits paid	**(14)**	(9)	**(1)**	(1)
Plan amendments	**–**	–	**–**	–
Curtailments	**(5)**	–	**(6)**	–
Benefit obligation at December 31	**$ 125**	$ 143	**$ 13**	$ 17

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2018**	2017	**2018**	2017
Change in plan assets:				
Fair value of plan assets at January 1	**$ 101**	$ 81	**$ –**	$ –
Actual return on plan assets	**(8)**	15	**–**	–
Employer contributions	**12**	14	**1**	1
Participant contributions	**–**	–	**–**	–
Benefits paid	**(14)**	(9)	**(1)**	(1)
Fair value of plan assets at December 31	**$ 91**	$ 101	**$ –**	$ –
Funded status of plans at December 31	**$ (34)**	$ (42)	**$ (13)**	$ (17)

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

The pension plans' projected benefit obligation, accumulated benefit obligation and fair value of plan assets as of December 31, 2018 and 2017 are as follows:

(in millions)	2018	2017
Projected benefit obligation	$ 125	$ 143
Accumulated benefit obligation	122	137
Fair value of plan assets	91	101

Pension and other postretirement benefit costs include the following components for 2018, 2017 and 2016:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2018	2017	2016	2018	2017	2016
Service cost	$ 10	$ 9	$ 11	$ 2	$ 2	$ 2
Interest cost	5	5	5	1	–	1
Expected return on plan assets	(7)	(6)	(6)	–	–	–
Amortization of transition obligation	–	–	–	–	–	–
Amortization of prior service cost	–	–	–	–	–	–
Amortization of net loss	2	2	2	–	–	–
Net periodic benefit cost	10	10	12	3	2	3
Curtailment (gain) loss	–	–	1	(4)	–	(6)
Settlement loss	–	–	11	–	–	–
Total benefit cost (benefit)	$ 10	$ 10	$ 24	$ (1)	$ 2	$ (3)

Service cost is classified as general and administrative expenses on the consolidated statements of operations. All other components of total benefit cost (benefit) are classified as other income (loss), net on the consolidated statements of operations.

Amounts recognized in other comprehensive income for the years ended December 31, 2018 and 2017 were as follows:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2018	2017	2018	2017
Net actuarial (loss) gain arising during the year	$ (2)	$ (11)	$ –	$ (2)
Amortization of prior service cost	–	–	–	–
Amortization of net loss	2	2	–	–
Settlements	–	–	–	–
Curtailments	5	–	3	–
Tax effect (1)	(1)	3	(1)	1
	$ 4	$ (6)	$ 2	$ (1)

(1) Deferred tax activity related to pension and other postretirement benefits was offset by a valuation allowance, resulting in no tax expense for all periods presented on the consolidated statements of operations.

Included in accumulated other comprehensive income as of December 31, 2018 and 2017 was a $34 million loss ($20 million net of tax) and a $42 million loss ($26 million net of tax), respectively, related to the Company's pension and other postretirement benefit plans. For the year ended December 31, 2018, $6 million was classified to accumulated other comprehensive income, primarily driven by actuarial gain 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 2019 is a $2 million net loss.

The assumptions used in the measurement of the Company's benefit obligations as of December 31, 2018 and 2017 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
Discount rate	4.35 %	3.75 %	4.35 %	3.75 %
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 2018, 2017 and 2016 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2018	2017	2016	**2018**	2017	2016
Discount rate	**4.35 %**	4.20 %	4.20 %	**4.35 %**	4.20 %	4.20 %
Expected return on plan assets	**7.00 %**	7.00 %	7.00 %	**n/a**	n/a	n/a
Rate of compensation increase	**3.50 %**	3.50 %	3.50 %	**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 2018 and 2017:

	2018	2017
Health care cost trend assumed for next year	**7%**	7%
Rate to which the cost trend is assumed to decline	**5%**	5%
Year that the rate reaches the ultimate trend rate	**2036**	2035

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

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

Pension Payments and Asset Management

In 2018, the Company contributed $12 million to its pension plans and $1 million to its other postretirement benefit plan. The Company expects to contribute $13 million to its pension and other postretirement benefit plans in 2019.

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

Pension Benefits	*(in millions)*	Other Postretirement Benefits	
2019	$ 22	2019	$ 1
2020	6	2020	1
2021	6	2021	1
2022	6	2022	1
2023	7	2023	1
Years 2024-2028	39	Years 2024-2028	5

The Company's overall investment strategy is to provide an adequate pool of assets to support both the long-term growth of plan assets and to ensure adequate liquidity exists for the near-term payment of benefit obligations to participants, retirees and beneficiaries. The Benefits Administration Committee of the Company, appointed by the Compensation Committee of the Board of Directors, administers the Company's pension plan assets. The Benefits Administration Committee believes long-term investment performance is a function of asset-class mix and restricts the composition of pension plan assets to a combination of cash and cash equivalents, domestic equity markets, international equity markets or investment grade fixed income assets.

The table below presents the allocations targeted by the Benefits Administration Committee and the actual weighted-average asset allocation of the Company's pension plan as of December 31, 2018, 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 %	26 %
Non-U.S. developed equity (2)	30 %	22 %
Emerging markets equity (3)	5 %	4 %
Fixed income (4)	28 %	23 %
Cash (5)	2 %	25 %
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 fixed income pension plan assets in the table below.

(5) Includes Cash and cash equivalent pension plan assets in the table below.

Utilizing the fair value hierarchy described in Note 7, the Company's fair value measurement of pension plan assets as of December 31, 2018 is as follows:

(in millions)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Measured within fair value hierarchy				
Equity securities:				
U.S. large cap growth equity (1)	$ 5	$ 5	$ –	$ –
U.S. large cap value equity (2)	5	5	–	–
U.S. small cap equity (3)	2	2	–	–
Non-U.S. equity (4)	20	20	–	–
Emerging markets equity (5)	3	3	–	–
Fixed income (6)	14	14	–	–
Cash and cash equivalents (7)	23	23	–	–
Total measured within fair value hierarchy	$ 72	$ 72	$ –	$ –
Measured at net asset value (8)				
Equity securities:				
U.S. large cap core equity (9)	12			
Fixed income (6)	7			
Total measured at net asset value	$ 19			
Total plan assets at fair value	$ 91			

Note: Footnotes are located after the prior year comparative table below.

Utilizing the fair value hierarchy described in Note 7, the Company's fair value measurement of pension plan assets at December 31, 2017 was as follows:

(in millions)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Measured within fair value hierarchy				
Equity securities:				
U.S. large cap growth equity (1)	$ 7	$ 7	$ –	$ –
U.S. large cap value equity (2)	8	8	–	–
U.S. small cap equity (3)	3	3	–	–
Non-U.S. equity (4)	30	30	–	–
Emerging markets equity (5)	5	5	–	–
Fixed income (6)	27	27	–	–
Cash and cash equivalents	3	3	–	–
Total measured within fair value hierarchy	$ 83	$ 83	$ –	$ –
Measured at net asset value (8)				
Equity securities:				
U.S. large cap core equity (9)	18			
Total measured at net asset value	$ 18			
Total plan assets at fair value	$ 101			

(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) Includes approximately $21 million for anticipated lump sum distributions resulting from the Fayetteville Shale sale in December 2018.

(8) Plan assets for which fair value was measured using net asset value as a practical expedient.

(9) An institutional fund that seeks to replicate the performance of the S&P 500 Index before fees.

The Company's pension plan assets that are classified as Level 1 are the investments comprised of either cash or investments in open-ended mutual funds which produce a daily net asset value that is validated with a sufficient level of observable activity to support classification of the fair value measurement as Level 1. Due to the Company's implementation of Accounting Standards Update No. 2015-07, assets measured using net asset value as a practical expedient have not been classified in the fair value hierarchy. No concentration of risk arising within or across categories of plan assets exists due to any significant investments in a single entity, industry, country or investment fund.

(13) STOCK-BASED COMPENSATION

The Southwestern Energy Company 2013 Incentive Plan was adopted in February 2013, approved by stockholders in May 2013 and amended and restated per stockholders' approval in May 2016 and further amended in May 2017 (the "2013 Plan"). The 2013 Plan provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries.

The 2013 Plan provides for grants of options, stock appreciation rights, and shares of restricted stock and restricted stock units to employees, officers and directors that, in the aggregate, do not exceed 52,700,000 shares. The types of incentives that may be awarded are comprehensive and are intended to enable the Company's Board of Directors to structure the most appropriate incentives and to address changes in income tax laws which may be enacted over the term of the 2013 Plan.

The Company's stock-based compensation is classified as either equity or liability awards in accordance with generally accepted accounting principles. The fair value of an equity-classified award is determined at the grant date and is amortized to general and administrative expense on a straight-line basis over the vesting period of the award. The fair value of a liability-classified award is determined on a quarterly basis beginning at the grant date until final vesting. Changes in the fair value of liability-classified awards are recorded to general and administrative expense over the vesting period of the award. A portion of this general and administrative expense is capitalized into natural gas and oil properties, included in property and equipment. Generally, stock options granted to employees and directors vest ratably over three years from the grant date and expire seven years from the date of grant. The Company issues shares of restricted stock or restricted stock units to employees and directors which generally vest over four years. Restricted stock, restricted stock units and stock options granted to participants under the 2013 Plan immediately vest upon death, disability or retirement (subject to a minimum of three years of service).

In June 2018, the Company announced a workforce reduction. Unvested stock-based awards of the affected employees were subsequently cancelled and the approximate fair value of a portion of those cancelled awards was included in a cash severance payment that was paid in the third quarter of 2018. Stock-based compensation costs recognized prior to the cancellation as either general and administrative expense or capitalized expense were reversed and the severance payments were subsequently recognized as restructuring charges for the year ended December 31, 2018 on the consolidated statements of operations.

In December 2018, the Company closed on the sale of the equity in certain of its subsidiaries that owned and operated its Fayetteville Shale E&P and related midstream gathering assets in Arkansas. As part of this transaction, most employees associated with those assets became employees of the buyer although the employment of some was or will be terminated. All affected employees were offered a severance package, which included a one-time cash payment depending on length of service and, if applicable, the current value of a portion of equity awards that were forfeited. Stock-based compensation costs recognized prior to the cancellation as either general and administrative expense or capitalized expense were reversed and the severance payments were subsequently recognized as restructuring charges for the year ended December 31, 2018 on the consolidated statements of operations.

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

Equity-Classified Awards

Equity-Classified Stock Options

The Company recorded the following compensation costs related to stock options for the years ended December 31, 2018, 2017 and 2016:

(in millions)	**2018**	2017	2016
Stock options – general and administrative expense [(1)]	$ 2	$ 3	$ 6
Stock options – general and administrative expense capitalized	$ –	$ 1	$ 1

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

The Company also recorded a deferred tax asset of less than $1 million, $1 million and $2 million related to stock options in 2018, 2017 and 2016, respectively. Unrecognized compensation cost related to the Company's unvested stock options totaled $1 million at December 31, 2018. This cost is expected to be recognized over a weighted-average period of one year.

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. The Company did not issue equity-classified stock options in 2018.

Assumptions	2018	2017	2016
Risk-free interest rate	–	1.9%	1.4%
Expected dividend yield	–	–	–
Expected volatility	–	50.5%	41.0%
Expected term	–	5 years	5 years

The following tables summarize stock option activity for the years 2018, 2017 and 2016, and provide information for options outstanding at December 31 of each year:

	2018			2017			2016		
	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	6,020	$	19.43	5,416	$	23.46	5,623	$	24.57
Granted [1]	–	$	–	1,604	$	8.00	155	$	8.60
Exercised	–	$	–	–	$	–	(45)	$	7.74
Forfeited or expired	(842)	$	33.99	(1,000)	$	22.93	(317)	$	38.01
Options outstanding at December 31	5,178	$	17.06	6,020	$	19.43	5,416	$	23.46

(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. The Company did not issue equity-classified stock options in 2018.

	Options Outstanding				Options Exercisable			
Range of Exercise Prices	Options Outstanding at December 31, 2018		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable at December 31, 2018		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
	(in thousands)			*(years)*	*(in thousands)*			*(years)*
$5.22-$29.42	3,517	$	8.68	4.4	2,605	$	8.96	4.1
$30.59-$35.64	1,135	$	32.26	2.1	1,135	$	32.26	2.1
$36.69-$39.48	436	$	38.97	1.9	436	$	38.97	1.9
$40.15-$49.00	90	$	46.55	2.4	90	$	46.55	2.4
	5,178	$	17.06	3.6	4,266	$	19.02	3.3

There were no options granted in 2018. The weighted-average grant date fair value of options granted during the years 2017 and 2016 were $3.47 and $3.22, respectively. There were no options exercised in 2018 or 2017. The total intrinsic value of options exercised during 2016 was less than $1 million.

Equity-Classified Restricted Stock

The Company recorded the following compensation costs related to restricted stock grants for the years ended December 31, 2018, 2017 and 2016:

(in millions)	2018		2017		2016	
Restricted stock grants – general and administrative expense [1]	$	9	$	16	$	33
Restricted stock grants – general and administrative expense capitalized	$	5	$	11	$	8

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

The Company also recorded a deferred tax asset of $2 million related to restricted stock for the year ended December 31, 2018, compared to a deferred tax assets of $9 million and $12 million for 2017 and 2016, respectively. As of December 31, 2018, there was $15 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 two years.

The following table summarizes the restricted stock activity for the years 2018, 2017 and 2016, and provides information for restricted stock outstanding at December 31 of each year:

	2018			2017			2016		
	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	6,254	$	8.85	3,321	$	11.85	7,222	$	13.24
Granted	350	$	4.72	5,055	$	8.38	81 [(2)]	$	8.56
Vested	(2,058) [(1)]	$	9.24	(1,380)	$	13.28	(3,817) [(3)]	$	11.34
Forfeited	(1,829)	$	9.01	(742)	$	10.04	(165)	$	12.05
Unvested shares at December 31	2,717	$	7.91	6,254	$	8.85	3,321	$	11.85

(1) Includes 1,287,636 shares forfeited as a result of the reduction in workforce for the year ended December 31, 2018.

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

(3) 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 $2 million for 2018, $42 million for 2017 and $1 million for 2016. The total fair value of shares vested were $19 million for 2018, $18 million for 2017 and $43 million for 2016.

Equity-Classified Performance Units

The Company recorded compensation costs related to equity-classified performance units for the years ended December 31, 2018, 2017 and 2016. The performance units awarded in 2018, 2017 and 2016 included a market condition based on relative Total Shareholder Return ("TSR"). The grant date fair value is calculated using the closing price of the Company's common stock at the grant date and a Monte Carlo model to estimate the TSR market condition. The estimated fair value is amortized to compensation expense on a straight-line basis over the vesting period of the award.

(in millions)	2018		2017		2016	
Performance units – general and administrative expense [(1)]	$	3	$	5	$	9
Performance units – general and administrative expense capitalized	$	1	$	2	$	1

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

The Company also recorded a deferred tax asset of $1 million related to equity-classified performance units for the year ended December 31, 2018, compared to deferred tax assets of $3 million and $4 million in 2017 and 2016, respectively. As of December 31, 2018, there was $3 million of total unrecognized compensation cost related to unvested equity-classified performance units that is expected to be recognized over a weighted-average period of one year.

The following table summarizes equity-classified performance unit activity to be paid out in Company stock for the years ended December 31, 2018, 2017 and 2016, and provides information for unvested units as of December 31, 2018, 2017 and 2016:

	2018		2017		2016	
	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	**1,084**	**$ 10.12**	719	$ 11.46	407	$ 36.65
Granted	**–**	**$ –**	1,197	$ 10.47	1,503	$ 8.60
Vested	**(290)**	**$ 10.47**	(325)	$ 12.21	(889)[3]	$ 12.78
Forfeited	**(196)[2]**	**$ 9.94**	(507)	$ 9.53	(302)[4]	$ 11.26
Unvested shares at December 31	**598**	**$ 10.01**	1,084	$ 10.12	719	$ 11.46

(1) These amounts reflect the number of performance units granted in thousands. The actual payout of shares may range from a minimum of zero shares to a maximum of two shares per unit contingent upon TSR. The performance units have a three-year vesting term and the actual disbursement of shares, if any, is determined during the first quarter following the end of the three-year vesting period.

(2) Includes 144,927 units related to the reduction in workforce for the year ended December 31, 2018.

(3) 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.

(4) 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 Awards

Liability-Classified Restricted Stock Units

In the first quarter of 2018, the Company granted restricted stock units that vest over a period of four years and are payable in either cash or shares at the option of the Compensation Committee of the Company's Board of Directors. The Company has accounted for these as liability-classified awards, and accordingly changes in the market value of the instruments will be recorded to general and administrative expense and capitalized expense over the vesting period of the award.

(in millions)	2018
Restricted stock units – general and administrative expense	**$ 4**
Restricted stock units – general and administrative expense capitalized	**$ 3**

The Company also recorded a deferred tax asset of $2 million related to liability-classified restricted stock units for the year ended December 31, 2018. As of December 31, 2018, there was $22 million of total unrecognized compensation cost related to liability-classified restricted stock units that is expected to be recognized over a weighted-average period of three years.

The following table summarizes restricted stock unit activity to be paid out in cash for the year ended December 31, 2018 and provides information for unvested units as of December 31, 2018:

	Number of Units	Weighted Average Fair Value
	(in thousands)	
Unvested shares at January 1, 2018	–	$ –
Granted	12,216	$ 3.69
Vested	(232)	$ 5.14
Forfeited [1]	(3,782)	$ 4.86
Unvested units at December 31, 2018	**8,202**	**$ 3.41**

(1) Includes 2,766,610 units related to the reduction in workforce for the year ended December 31, 2018.

Liability-Classified Performance Units

In the first quarter of 2018, the Company granted performance units that vest over a three-year period and are payable in either cash or shares at the option of the Compensation Committee of the Company's Board of Directors. The Company has accounted for these as liability-classified awards, and accordingly changes in the fair market value of the instruments will be recorded to general and administrative expense and capitalized expense over the vesting period of the awards. The liability-classified performance unit awards include a performance condition based on cash flow per debt-adjusted share and two market conditions, one based on absolute TSR and the other on relative TSR as compared to a group of the Company's peers, collectively the "Performance Measures." The fair values of the two market conditions are calculated by Monte Carlo models on a quarterly basis.

(in millions)	2018
Liability-classified performance units – general and administrative expense	$ 2
Liability-classified performance units – general and administrative expense capitalized	$ –

The Company also recorded a deferred tax asset of $1 million related to liability-classified performance units for the year ended December 31, 2018. As of December 31, 2018, there was $9 million of total unrecognized compensation cost related to liability-classified performance units. This cost is expected to be recognized over a weighted-average period of two years. The final value of the performance unit awards is contingent upon the Company's actual performance against the Performance Measures.

The following table summarizes liability-classified performance unit activity to be paid out in cash for the year ended December 31, 2018 and provides information for unvested units as of December 31, 2018:

	Number of Shares	Weighted Average Fair Value
	(in thousands)	
Unvested shares at January 1, 2018	–	$ –
Granted	3,200	$ 3.70
Vested	–	$ –
Forfeited [1]	(397)	$ 4.55
Unvested units at December 31, 2018	**2,803**	**$ 3.41**

(1) Includes 295,160 units related to the reduction in workforce for the year ended December 31, 2018.

(14) SEGMENT INFORMATION

The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and liquids. The Midstream segment generates revenue through the marketing of both Company and third-party produced natural gas and liquids volumes.

Prior to December 2018, the Midstream segment included the Company's natural gas gathering business associated with its Fayetteville Shale assets. With the closing of the Fayetteville Shale sale in December 2018, the Midstream segment consists almost entirely of the Company's marketing business.

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. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense, gain (loss) on derivatives, loss on early extinguishment of debt and other income (loss). The "Other" column includes items not related to the Company's reportable segments, including real estate and corporate items.

(in millions)	Exploration and Production	Midstream	Other	Total
2018 [1]				
Revenues from external customers	**$ 2,551**	**$ 1,311**	**$ –**	**$ 3,862**
Intersegment revenues	**(26)**	**2,434**	**–**	**2,408**
Depreciation, depletion and amortization expense	**514**	**46**	**–**	**560**
Impairments	**15**	**155**	**1**	**171**
Operating income (loss)	**794** [2]	**4** [3]	**(1)**	**797**
Interest expense [4]	**124**	**–**	**–**	**124**
Loss on derivatives	**(118)**	**–**	**–**	**(118)**
Loss on early extinguishment of debt	**–**	**–**	**(17)**	**(17)**
Other loss, net	**2**	**(2)**	**–**	**–**
Provision for income taxes [4]	**1**	**–**	**–**	**1**
Assets	**4,872** [5]	**539**	**386** [6]	**5,797**
Capital investments [7]	**1,231**	**9**	**8**	**1,248**
2017				
Revenues from external customers	$ 2,105	$ 1,098	$ –	$ 3,203
Intersegment revenues	(19)	2,100	–	2,081
Depreciation, depletion and amortization expense	440	64	–	504
Operating income (loss)	549	183	(1)	731
Interest expense [4]	135	–	–	135
Gain on derivatives	421	1	–	422
Loss on early extinguishment of debt	–	–	(70)	(70)
Other income, net	4	1	–	5
Benefit for income taxes [4]	(93)	–	–	(93)
Assets	5,109 [5]	1,288	1,124 [6]	7,521
Capital investments [7]	1,248	32	13	1,293
2016				
Revenues from external customers	$ 1,435	$ 1,001	$ –	$ 2,436
Intersegment revenues	(22)	1,568	–	1,546
Depreciation, depletion and amortization expense	371	65	–	436
Impairment of natural gas and oil properties	2,321	–	–	2,321
Operating income (loss)	(2,399) [8]	209 [9]	–	(2,190)
Interest expense [4]	87	1	–	88
Loss on derivatives	(338)	(1)	–	(339)
Loss on early extinguishment of debt	–	–	(51)	(51)
Other income (loss), net	–	(2)	(2)	(4)
Benefit for income taxes [4]	(29)	–	–	(29)
Assets	4,178 [5]	1,331	1,567 [6]	7,076
Capital investments [7]	623	21	4	648

(1) Includes the impact of approximately eleven months of Fayetteville Shale-related E&P and Midstream operations which were divested on December 3, 2018.

(2) Operating income for the E&P segment includes $37 million related to restructuring charges for the year ended December 31, 2018.

(3) Operating income for the Midstream segment includes $2 million related to restructuring charges for the year ended December 31, 2018.

(4) 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.

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

(6) Other assets represent corporate assets not allocated to segments and assets for non-reportable segments. At December 31, 2018, other assets includes approximately $201 million in cash and cash equivalents.

(7) Capital investments include a decrease of $53 million for 2018 and an increase of $43 million for 2016 related to the change in accrued expenditures between years. There was no impact to 2017.

(8) Operating loss for the E&P segment includes $81 million related to restructuring and other one-time charges for the year ended December 31, 2016.

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

Included in intersegment revenues of the Midstream segment are $2.3 billion, $1.9 billion and $1.3 billion for 2018, 2017 and 2016, 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.

(15) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

In April 2018, the Company entered into the 2018 credit facility. Pursuant to requirements under the indentures governing the Company's senior notes, each 100% owned subsidiary that became a guarantor of the 2018 credit facility also became a guarantor of each of the Company's senior notes (the "Guarantor Subsidiaries"). The Guarantor Subsidiaries also granted liens and security interests to support their guarantees under the 2018 credit facility but not of the senior notes. These guarantees are full and unconditional and joint and several among the Guarantor Subsidiaries. Certain of the Company's subsidiaries which are accounted for on a consolidated basis do not guarantee the 2018 credit facility and senior notes ("Non-Guarantor Subsidiaries"). See Note 8 for additional information on the Company's 2018 revolving credit facility and senior notes. At the closing of the Fayetteville Shale sale in December 2018, the Company's subsidiaries being sold were released from these guarantees. See Note 3 for additional information on the divestiture of the Company's Fayetteville Shale-related subsidiaries.

The following financial information reflects consolidating financial information of Southwestern Energy Company (the parent and issuer company), its Guarantor Subsidiaries on a combined basis and the Non-Guarantor Subsidiaries on a combined basis, prepared on the equity basis of accounting. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Year ended December 31, 2018:					
Operating Revenues:					
Gas sales	$ –	$ 1,998	$ –	$ –	$ 1,998
Oil sales	–	196	–	–	196
NGL sales	–	352	–	–	352
Marketing	–	1,222	–	–	1,222
Gas gathering	–	89	–	–	89
Other	–	5	–	–	5
	–	3,862	–	–	3,862
Operating Costs and Expenses:					
Marketing purchases	–	1,229	–	–	1,229
Operating expenses	–	785	–	–	785
General and administrative expenses	–	209	–	–	209
Restructuring charges	–	39	–	–	39
Depreciation, depletion and amortization	–	560	–	–	560
Impairments	–	171	–	–	171
Gain on sale of assets, net	–	(17)	–	–	(17)
Taxes, other than income taxes	–	89	–	–	89
	–	3,065	–	–	3,065
Operating Income	–	797	–	–	797
Interest Expense, Net	124	–	–	–	124
Loss on Derivatives	–	(118)	–	–	(118)
Loss on Early Extinguishment of Debt	(17)	–	–	–	(17)
Equity in Earnings of Subsidiaries	678	–	–	(678)	–
Income (Loss) Before Income Taxes	537	679	–	(678)	538
Provision for Income Taxes	–	1	–	–	1
Net Income (Loss)	$ 537	$ 678	$ –	$ (678)	$ 537
Mandatory convertible preferred stock dividend	–	–	–	–	–
Participating securities – mandatory convertible preferred stock	2	–	–	–	2
Net Income (Loss) Attributable to Common Stock	$ 535	$ 678	$ –	$ (678)	$ 535
Net Income (Loss)	$ 537	$ 678	$ –	$ (678)	$ 537
Other comprehensive income	8	–	–	–	8
Comprehensive Income (Loss)	$ 545	$ 678	$ –	$ (678)	$ 545

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Year ended December 31, 2017:					
Operating Revenues:					
Gas sales	$ –	$ 1,793	$ –	$ –	$ 1,793
Oil sales	–	102	–	–	102
NGL sales	–	206	–	–	206
Marketing	–	972	–	–	972
Gas gathering	–	126	–	–	126
Other	–	4	–	–	4
	–	3,203	–	–	3,203
Operating Costs and Expenses:					
Marketing purchases	–	976	–	–	976
Operating expenses	–	671	–	–	671
General and administrative expenses	–	233	–	–	233
Depreciation, depletion and amortization	–	504	–	–	504
Gain on sale of assets, net	–	(6)	–	–	(6)
Taxes, other than income taxes	–	94	–	–	94
	–	2,472	–	–	2,472
Operating Income	–	731	–	–	731
Interest Expense, Net	135	–	–	–	135
Gain on Derivatives	–	422	–	–	422
Loss on Early Extinguishment of Debt	(70)	–	–	–	(70)
Other Income, Net	–	5	–	–	5
Equity in Earnings of Subsidiaries	1,251	–	–	(1,251)	–
Income (Loss) Before Income Taxes	1,046	1,158	–	(1,251)	953
Benefit from Income Taxes	–	(93)	–	–	(93)
Net Income (Loss)	$ 1,046	$ 1,251	$ –	$ (1,251)	$ 1,046
Mandatory convertible preferred stock dividend	108	–	–	–	108
Participating securities – mandatory convertible preferred stock	123	–	–	–	123
Net Income (Loss) Attributable to Common Stock	$ 815	$ 1,251	$ –	$ (1,251)	$ 815
Net Income (Loss)	$ 1,046	$ 1,251	$ –	$ (1,251)	$ 1,046
Other comprehensive income	(5)	6	6	(12)	(5)
Comprehensive Income (Loss)	$ 1,041	$ 1,257	$ 6	$ (1,263)	$ 1,041

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Year ended December 31, 2016:					
Operating Revenues:					
Gas sales	$ –	$ 1,273	$ –	$ –	$ 1,273
Oil sales	–	69	–	–	69
NGL sales	–	92	–	–	92
Marketing	–	864	–	–	864
Gas gathering	–	138	–	–	138
	–	2,436	–	–	2,436
Operating Costs and Expenses:					
Marketing purchases	–	864	–	–	864
Operating expenses	–	592	–	–	592
General and administrative expenses	–	247	–	–	247
Restructuring charges	–	73	–	–	73
Depreciation, depletion and amortization	–	436	–	–	436
Impairments	–	2,266	55	–	2,321
Taxes, other than income taxes	–	93	–	–	93
	–	4,571	55	–	4,626
Operating Income	–	(2,135)	(55)	–	(2,190)
Interest Expense, Net	88	–	–	–	88
Loss on Derivatives	–	(339)	–	–	(339)
Loss on Early Extinguishment of Debt	(51)	–	–	–	(51)
Other Loss, Net	–	(4)	–	–	(4)
Equity in Earnings of Subsidiaries	(2,504)	(55)	–	2,559	–
Income (Loss) Before Income Taxes	(2,643)	(2,533)	(55)	2,559	(2,672)
Benefit from Income Taxes	–	(29)	–	–	(29)
Net Income (Loss)	$ (2,643)	$ (2,504)	$ (55)	$ 2,559	$ (2,643)
Mandatory convertible preferred stock dividend	108	–	–	–	108
Participating securities – mandatory convertible preferred stock	–	–	–	–	–
Net Income (Loss) Attributable to Common Stock	$ (2,751)	$ (2,504)	$ (55)	$ 2,559	$ (2,751)
Net Income (Loss)	$ (2,643)	$ (2,504)	$ (55)	$ 2,559	$ (2,643)
Other comprehensive income	9	3	3	(6)	9
Comprehensive Income (Loss)	$ (2,634)	$ (2,501)	$ (52)	$ 2,553	$ (2,634)

CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
December 31, 2018:					
ASSETS					
Cash and cash equivalents	$ 201	$ –	$ –	$ –	$ 201
Accounts receivable, net	4	577	–	–	581
Other current assets	8	166	–	–	174
Total current assets	213	743	–	–	956
Intercompany receivables	7,932	–	–	(7,932)	–
Natural gas and oil properties, using the full cost method	–	24,128	52	–	24,180
Gathering systems	–	11	27	–	38
Other	197	290	–	–	487
Less: Accumulated depreciation, depletion and amortization	(154)	(19,840)	(55)	–	(20,049)
Total property and equipment, net	43	4,589	24	–	4,656
Investments in subsidiaries (equity method)	–	24	–	(24)	–
Other long-term assets	19	166	–	–	185
TOTAL ASSETS	$ 8,207	$ 5,522	$ 24	$ (7,956)	$ 5,797
LIABILITIES AND EQUITY					
Accounts payable	$ 113	$ 496	$ –	$ –	$ 609
Other current liabilities	115	122	–	–	237
Total current liabilities	228	618	–	–	846
Intercompany payables	–	7,932	–	(7,932)	–
Long-term debt	2,318	–	–	–	2,318
Pension and other postretirement liabilities	46	–	–	–	46
Other long-term liabilities	54	171	–	–	225
Negative carrying amount of subsidiaries, net	3,199	–	–	(3,199)	–
Total long-term liabilities	5,617	171	–	(3,199)	2,589
Commitments and contingencies					
Total equity (accumulated deficit)	2,362	(3,199)	24	3,175	2,362
TOTAL LIABILITIES AND EQUITY	$ 8,207	$ 5,522	$ 24	$ (7,956)	$ 5,797

CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
December 31, 2017:					
ASSETS					
Cash and cash equivalents	$ 914	$ 2	$ –	$ –	$ 916
Accounts receivable, net	–	428	–	–	428
Other current assets	10	155	–	–	165
Total current assets	924	585	–	–	1,509
Intercompany receivables	7,978	–	–	(7,978)	–
Natural gas and oil properties, using the full cost method	–	23,834	56	–	23,890
Gathering systems	–	1,288	27	–	1,315
Other	207	357	–	–	564
Less: Accumulated depreciation, depletion and amortization	(134)	(19,804)	(59)	–	(19,997)
Total property and equipment, net	73	5,675	24	–	5,772
Investments in subsidiaries (equity method)	–	24	–	(24)	–
Other long-term assets	16	224	–	–	240
TOTAL ASSETS	$ 8,991	$ 6,508	$ 24	$ (8,002)	$ 7,521
LIABILITIES AND EQUITY					
Accounts payable	$ 73	$ 460	$ –	$ –	$ 533
Other current liabilities	110	137	–	–	247
Total current liabilities	183	597	–	–	780
Intercompany payables	–	7,978	–	(7,978)	–
Long-term debt	4,391	–	–	–	4,391
Pension and other postretirement liabilities	58	–	–	–	58
Other long-term liabilities	13	300	–	–	313
Negative carrying amount of subsidiaries, net	2,367	–	–	(2,367)	–
Total long-term liabilities	6,829	300	–	(2,367)	4,762
Commitments and contingencies					
Total equity (accumulated deficit)	1,979	(2,367)	24	2,343	1,979
TOTAL LIABILITIES AND EQUITY	$ 8,991	$ 6,508	$ 24	$ (8,002)	$ 7,521

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

(in millions)	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Year ended December 31, 2018:					
Net cash provided by (used in) operating activities	$ 304	$ 1,595	$ –	$ (676)	$ 1,223
Investing activities:					
Capital investments	(20)	(1,270)	–	–	(1,290)
Proceeds from the sale of property and equipment	–	1,643	–	–	1,643
Other	–	6	–	–	6
Net cash used in investing activities	(20)	379	–	–	359
Financing activities					
Intercompany activities	1,300	(1,976)	–	676	–
Payments on long-term debt	(2,095)	–	–	–	(2,095)
Payments on revolving credit facility	(1,983)	–	–	–	(1,983)
Borrowings under revolving credit facility	1,983	–	–	–	1,983
Purchase of treasury stock	(180)	–	–	–	(180)
Preferred stock dividend	(27)	–	–	–	(27)
Other	5	–	–	–	5
Net cash provided by (used in) financing activities	(997)	(1,976)	–	676	(2,297)
Increase (decrease) in cash and cash equivalents	(713)	(2)	–	–	(715)
Cash and cash equivalents at beginning of year	914	2	–	–	916
Cash and cash equivalents at end of year	$ 201	$ –	$ –	$ –	$ 201
Year ended December 31, 2017:					
Net cash provided by (used in) operating activities	$ 1,019	$ 1,327	$ –	$ (1,249)	$ 1,097
Investing activities:					
Capital investments	(13)	(1,250)	(5)	–	(1,268)
Proceeds from the sale of property and equipment	1	9	–	–	10
Other	1	5	–	–	6
Net cash used in investing activities	(11)	(1,236)	(5)	–	(1,252)
Financing activities					
Intercompany activities	(1,158)	(96)	5	1,249	–
Payments on short-term debt	(328)	–	–	–	(328)
Payments on long-term debt	(1,139)	–	–	–	(1,139)
Proceeds from issuance of long-term debt	1,150	–	–	–	1,150
Preferred stock dividend	(16)	–	–	–	(16)
Other	(19)	–	–	–	(19)
Net cash provided by (used in) financing activities	(1,510)	(96)	5	1,249	(352)
Increase (decrease) in cash and cash equivalents	(502)	(5)	–	–	(507)
Cash and cash equivalents at beginning of year	1,416	7	–	–	1,423
Cash and cash equivalents at end of year	$ 914	$ 2	$ –	$ –	$ 916
Year ended December 31, 2016:					
Net cash provided by (used in) operating activities	$ (2,610)	$ 550	$ –	$ 2,558	$ 498
Investing activities:					
Capital investments	(3)	(590)	–	–	(593)
Proceeds from the sale of property and equipment	2	428	–	–	430
Other	1	–	–	–	1
Net cash used in investing activities	–	(162)	–	–	(162)
Financing activities					
Intercompany activities	2,950	(392)	–	(2,558)	–
Payments on long-term debt	(1,175)	–	–	–	(1,175)
Payments on revolving credit facility	(3,268)	–	–	–	(3,268)
Borrowings on revolving credit facility	3,152	–	–	–	3,152
Payments on commercial paper	(242)	–	–	–	(242)
Borrowings under commercial paper	242	–	–	–	242
Proceeds from issuance of long-term debt	1,191	–	–	–	1,191
Proceeds from issuance of common stock	1,247	–	–	–	1,247
Preferred stock dividend	(27)	–	–	–	(27)
Other	(48)	–	–	–	(48)
Net cash provided by (used in) financing activities	4,022	(392)	–	(2,558)	1,072
Increase (decrease) in cash and cash equivalents	1,412	(4)	–	–	1,408
Cash and cash equivalents at beginning of year	4	11	–	–	15
Cash and cash equivalents at end of year	$ 1,416	$ 7	$ –	$ –	$ 1,423

SUPPLEMENTAL QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2018 and 2017:

(in millions, except share amounts)	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
		2018		
Operating revenues	**$ 920**	**$ 816**	**$ 951**	**$ 1,175**
Operating income	**255**	**124**	**66**	**352**
Net income (loss) attributable to common stock	**205**	**51**	**(29)**	**307**
Earnings (loss) per share – Basic	**0.36**	**0.09**	**(0.05)**	**0.54**
Earnings (loss) per share – Diluted	**0.36**	**0.09**	**(0.05)**	**0.54**
		2017		
Operating revenues	$ 846	$ 811	$ 737	$ 809
Operating income	266	188	110	167
Net income attributable to common stock	281	224	43	267
Earnings per share – Basic	0.57	0.45	0.09	0.53
Earnings per share – Diluted	0.57	0.45	0.09	0.53

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, 2018 and 2017:

(in millions)	**2018**	2017
Proved properties	**$ 22,425**	$ 22,073
Unproved properties	**1,755**	1,817
Total capitalized costs	**24,180**	23,890
Less: Accumulated depreciation, depletion and amortization	**(19,761)**	(19,287)
Net capitalized costs	**$ 4,419**	$ 4,603

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, 2018:

(in millions)	2018	2017	2016	Prior	**Total**
Property acquisition costs	$ 49	$ 70	$ 12	$ 1,346	**$ 1,477**
Exploration and development costs	42	23	6	23	**94**
Capitalized interest	77	45	28	34	**184**
	$ 168	$ 138	$ 46	$ 1,403	**$ 1,755**

Of the total net unevaluated costs excluded from amortization as of December 31, 2018, approximately $1.5 billion is related to undeveloped properties in Southwest Appalachia (acquired in 2014), approximately $23 million is related to the acquisition of the Company's undeveloped properties in Northeast Appalachia and approximately $11 million is related to the acquisition of undeveloped properties outside the Appalachian Basin. Additionally, the Company has approximately $184 million of unevaluated capitalized interest and $77 million of unevaluated costs related to wells in progress. The remaining costs excluded from amortization are related to properties which are not individually significant and on which the evaluation process has not been completed. The timing and amount of property acquisition and seismic costs included in the amortization computation will depend on the location and timing of drilling wells, results of drilling and other assessments. The Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

Costs Incurred in Natural Gas and Oil Exploration and Development

The table below sets forth capitalized costs incurred in natural gas and oil property acquisition, exploration and development activities:

(in millions, except per Mcfe amounts)	2018	2017	2016
Unproved property acquisition costs	$ 164	$ 194	$ 171
Exploration costs	5	22	17
Development costs	1,014	1,024	433
Capitalized costs incurred	1,183	1,240	621
Full cost pool amortization per Mcfe	$ 0.51	$ 0.45	$ 0.38

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $115 million, $113 million and $152 million during 2018, 2017 and 2016, 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 $90 million, $99 million and $87 million during 2018, 2017 and 2016, respectively, which were directly related to the acquisition, exploration and development of the Company's natural gas and oil properties.

Results of Operations from Natural Gas and Oil Producing Activities

The table below sets forth the results of operations from natural gas and oil producing activities:

(in millions)	2018	2017	2016
Sales	$ 2,525	$ 2,086	$ 1,413
Production (lifting) costs	(974)	(891)	(839)
Depreciation, depletion and amortization	(514)	(440)	(371)
Impairment of natural gas and oil properties	–	–	(2,321)
	1,037	755	(2,118)
Provision (benefit) for income taxes (1)	–	–	–
Results of operations (2)	$ 1,037	$ 755	$ (2,118)

(1) Prior to the recognition of a valuation allowance, in 2018, 2017 and 2016 the Company recognized income tax provisions of $254 million, $287 million and $805 million, respectively.

(2) Results of operations exclude the gain (loss) on unsettled commodity derivative instruments. See Note 5 – "Derivatives and Risk Management".

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

Natural Gas and Oil Reserve Quantities

The Company engaged the services of Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm, to audit the reserves estimated by the Company's reservoir engineers. In conducting its audit, the engineers and geologists of NSAI studied the Company's major properties in detail and independently developed reserve estimates. NSAI's audit consists primarily of substantive testing, which includes a detailed review of the Company's major properties, and accounted for approximately 99% of the present worth of the Company's total proved reserves as of December 31 of 2018, 2017 and 2016. 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 2018, 2017 and 2016, all of which were located in the United States:

	Natural Gas *(Bcf)*	Oil *(MBbls)*	NGL *(MBbls)*	**Total** ***(Bcfe)***
December 31, 2015	**5,917**	**8,753**	**40,947**	**6,215**
Revisions of previous estimates due to price	(983)	(582)	(8,337)	**(1,037)**
Revisions of previous estimates other than price	537	2,146	22,131	**683**
Extensions, discoveries and other additions	198	2,417	11,576	**282**
Production	(788)	(2,192)	(12,372)	**(875)**
Acquisition of reserves in place	–	–	–	**–**
Disposition of reserves in place	(15)	(19)	(14)	**(15)**
December 31, 2016	**4,866**	**10,523**	**53,931**	**5,253**
Revisions of previous estimates due to price	1,327	3,197	57,447	**1,691**
Revisions of previous estimates other than price	571	(1,529)	13,102	**641**
Extensions, discoveries and other additions (1)	5,159	55,772	432,220	**8,087**
Production	(797)	(2,327)	(14,245)	**(897)**
Acquisition of reserves in place	–	–	–	**–**
Disposition of reserves in place	–	–	–	**–**
December 31, 2017	**11,126**	**65,636**	**542,455**	**14,775**
Revisions of previous estimates due to price	**96**	**788**	**8,912**	**154**
Revisions of previous estimates other than price	**316**	**410**	**8,855**	**372**
Extensions, discoveries and other additions	**753**	**5,830**	**36,823**	**1,009**
Production	**(807)**	**(3,407)**	**(19,706)**	**(946)**
Acquisition of reserves in place	**–**	**–**	**–**	**–**
Disposition of reserves in place (2)	**(3,440)**	**(250)**	**(276)**	**(3,443)**
December 31, 2018	**8,044**	**69,007**	**577,063**	**11,921**

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

(2) The 2018 disposition is primarily associated with the Fayetteville Shale sale.

	Natural Gas *(Bcf)*	Oil *(MBbls)*	NGL *(MBbls)*	**Total** ***(Bcfe)***
Proved developed reserves as of:				
December 31, 2016	4,789	10,523	53,931	**5,176**
December 31, 2017	6,979	14,513	142,213	**7,920**
December 31, 2018	**4,395**	**18,037**	**175,480**	**5,557**
Proved undeveloped reserves as of:				
December 31, 2016	77	–	–	**77**
December 31, 2017	4,147	51,123	400,242	**6,855**
December 31, 2018	**3,649**	**50,970**	**401,583**	**6,364**

The Company's estimated proved natural gas, oil and NGL reserves were 11,921 Bcfe at December 31, 2018, compared to 14,775 Bcfe at December 31, 2017. The Company's reserves decreased in 2018, compared to 2017, as the disposition of the reserves related to the Fayetteville Shale was only partially offset by positive extensions, discoveries, other additions and revisions in the Appalachian Basin. The increase in the Company's reserves in 2017 primarily resulted through extensions, discoveries and other additions in the Appalachian Basin along with increases in both price and performance revisions across the portfolio. The decrease in the Company's reserves in 2016 was primarily due to the decrease in commodity prices.

The following table summarizes the changes in reserves for 2016, 2017 and 2018:

(in Bcfe)	Appalachia Northeast	Appalachia Southwest	Fayetteville Shale [1]	Other [2]	Total
December 31, 2015	**2,319**	**611**	**3,281**	**4**	**6,215**
Net revisions					
Price revisions	(794)	(127)	(116)	–	**(1,037)**
Performance and production revisions	318	199	163	3	**683**
Total net revisions	(476)	72	47	3	**(354)**
Extensions, discoveries and other additions					
Proved developed	81	157	19	–	**257**
Proved undeveloped	–	–	25	–	**25**
Total reserve additions	81	157	44	–	**282**
Production	(350)	(148)	(375)	(2)	**(875)**
Acquisition of reserves in place	–	–	–	–	**–**
Disposition of reserves in place	–	(15)	–	–	**(15)**
December 31, 2016	**1,574**	**677**	**2,997**	**5**	**5,253**
Net revisions					
Price revisions	903	738	49	1	**1,691**
Performance and production revisions	154	125	358	4	**641**
Total net revisions	1,057	863	407	5	**2,332**
Extensions, discoveries and other additions					
Proved developed	790	419	48	1	**1,258**
Proved undeveloped	1,100	5,186	543	–	**6,829**
Total reserve additions	1,890	5,605	591	1	**8,087**
Production	(395)	(183)	(316)	(3)	**(897)**
Acquisition of reserves in place	–	–	–	–	**–**
Disposition of reserves in place	–	–	–	–	**–**
December 31, 2017	**4,126**	**6,962**	**3,679**	**8**	**14,775**
Net revisions					
Price revisions	**41**	**106**	**6**	**1**	**154**
Performance and production revisions	**107**	**272**	**(6)**	**(1)**	**372**
Total net revisions	**148**	**378**	**–**	**–**	**526**
Extensions, discoveries and other additions					
Proved developed	**154**	**22**	**1**	**–**	**177**
Proved undeveloped	**397**	**435**	**–**	**–**	**832**
Total reserve additions	**551**	**457**	**1**	**–**	**1,009**
Production	**(459)**	**(243)**	**(243)**	**(1)**	**(946)**
Acquisition of reserves in place	**–**	**–**	**–**	**–**	**–**
Disposition of reserves in place	**–**	**–**	**(3,437)**	**(6)**	**(3,443)**
December 31, 2018	**4,366**	**7,554**	**–**	**1**	**11,921**

(1) The Fayetteville Shale E&P assets and associated reserves were divested December 3, 2018.

(2) Other includes properties outside of the Appalachian Basin and Fayetteville Shale.

The Company's December 31, 2018 proved reserves included 190 Bcfe of proved undeveloped reserves from 30 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 $24 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, 2017 proved reserves included 1,375 Bcfe of proved undeveloped reserves from 330 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but that have a negative $124 million present value when discounted at 10%. The Company's December 31, 2016 proved reserves included 77 Bcfe of proved undeveloped reserves from 15 locations that had a positive present value on an undiscounted basis in compliance with proved reserve requirements, but that have a negative $11 million present value when discounted at 10%.

The Company 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, 2018, 2017 and 2016 are calculated after income taxes, discounted using a 10% annual discount rate and do not purport to present the fair market value of the Company's proved gas, oil and NGL reserves:

(in millions)	2018	2017	2016
Future cash inflows	$ 34,523	$ 36,576	$ 9,064
Future production costs	(15,347)	(18,390)	(5,880)
Future development costs [1]	(4,095)	(4,676)	(485)
Future income tax expense [2]	(2,079)	(1,342)	–
Future net cash flows	13,002	12,168	2,699
10% annual discount for estimated timing of cash flows	(7,003)	(6,606)	(1,034)
Standardized measure of discounted future net cash flows	$ 5,999	$ 5,562	$ 1,665

(1) Includes abandonment costs.

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

Under the standardized measure, future cash inflows were estimated by applying an average price from the first day of each month from the previous 12 months, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Prices used for the standardized measure above were as follows:

(in millions)	2018	2017	2016
Natural gas *(per MMBtu)*	$ 3.10	$ 2.98	$ 2.48
Oil *(per Bbl)*	65.56	47.79	39.25
NGLs *(per Bbl)*	17.64	14.41	6.74

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 2018, 2017 and 2016:

(in millions)	2018	2017	2016
Standardized measure, beginning of year	$ 5,562	$ 1,665	$ 2,417
Sales and transfers of natural gas and oil produced, net of production costs	(1,564)	(1,191)	(574)
Net changes in prices and production costs	2,162	1,963	(415)
Extensions, discoveries, and other additions, net of future production and development costs	335	1,715	45
Acquisition of reserves in place	–	–	–
Sales of reserves in place	(2,022)	–	(10)
Revisions of previous quantity estimates	361	1,721	(140)
Net change in income taxes	(304)	(222)	–
Changes in estimated future development costs	(166)	(6)	71
Previously estimated development costs incurred during the year	536	55	114
Changes in production rates (timing) and other	521	(304)	(85)
Accretion of discount	578	166	242
Standardized measure, end of year	$ 5,999	$ 5,562	$ 1,665

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, 2018 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, 2018, 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 89 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 89 of this Annual Report.

ITEM 9B. OTHER INFORMATION

On February 25, 2019, the Compensation Committee of the Board of Directors of Southwestern Energy Company (the "Company") granted, subject to the approval of the Board, long-term incentives under the Company's 2013 Incentive Plan, as amended (the "Plan"), to its principal executive officer, principal financial officer and other named executive officers. On February 26, 2019, the Company's Board approved these grants.

The grants were comprised of two types of awards, the principal features of which are:

Restricted Stock Units. Each restricted stock unit that vests will entitle the holder to receive, at the Compensation Committee's option, either one share of common stock of the Company or a cash amount equal to the closing price of the Company's common stock on the vesting date. 25% of the restricted stock units vest on each of the first through the fourth anniversaries of the date of grant, provided the grantee is still an employee of the Company on the vesting date; however, all restricted stock units vest in the case of the grantee's Retirement, death or Disability or on a Change in Control, as defined in the Plan.

Performance Units. Each performance unit that vests will entitle the holder to receive a value of 0 to 2 shares of common stock of the Company depending on the Company's performance regarding specified metrics over the years 2019-2021, payable at the Compensation Committee's discretion either in shares of the Company's common stock or a cash amount equal to the closing price of the Company's common stock on the vesting date. The vesting date is the third anniversary of the date of grant, provided the grantee is still an employee of the Company on the vesting date; however, a pro rata portion of performance units vest in the case of the grantee's Retirement, death or Disability, as defined in the Plan, and on a Change in Control, as defined in the Plan, the award vests at the greater of target value and the projected value as if the performance period had been completed (without pro ration). The determination of the value of each unit from 0 to 2 shares of common stock of the Company is based on the achievement of threshold, target or maximum goals on the following metrics over a three-year performance period, being the calendar years 2019-2021:

- 50% Relative Total Shareholder Return – the difference between (a) the average of the closing prices for the Company's common stock on the last 20 trading days of 2021 plus all dividends paid on account of one share of the Company's common stock and (b) the average of the closing prices for the last 20 trading days of 2018, as compared to the same calculation for a specified group of the Company's peers.

- 25% Absolute Total Shareholder Return – the difference between (a) the average of the closing prices for the Company's common stock on the last 20 trading days of 2021 plus all dividends paid on account of one share of the Company's common stock and (b) the average of the closing prices for the last 20 trading days of 2018.

- 25% Return on Average Capital Employed – calculated by dividing (i) the average of net cash provided by operating activities from the Consolidated Statement of Cash Flows less "changes in assets and liabilities" included in the Operating Activities section of the Consolidated Statement of Cash Flows for the performance period by the sum of (ii) the product of the twenty-day average stock price immediately prior to the first day of the performance period and the diluted weighted average number of shares of common stock of the Company outstanding for the fourth quarter of the year prior to the beginning of the performance period, (iii) gross debt of the Company (net of cash and cash equivalents) outstanding on December 31 of the year prior to the beginning of the performance period, and (iv) the sum of (a) the product of the number of shares of common stock the Company issued during the performance period and the price of said shares and (b) the amount of additional net debt incurred during the performance period, which sum shall then be reduced by (c) the amount by which any net debt is reduced during the performance period and (d) the product of the number of shares of common stock of the company purchased by the company during the performance period and the price of said shares, with each occurrence of the above in (a) – (d) multiplied by a fraction in which the denominator equals the total number of quarters in the Performance Period (12) and the numerator equals the remaining number of quarters following each occurrence of the above in (a) – (d) plus one.

For each portion, a threshold level must be achieved for any amount to be payable. Performance at target level for all three metrics will result in a payout equal to one share per unit (or its value in cash), and there is a maximum level that, if all three metrics perform at maximum, entitles the holder to two shares (or their value in cash) per unit. The Relative Total Shareholder Return portion will be deemed not to exceed the target level if the Absolute Total Shareholder Return is negative, and if the Relative Total Shareholder Return portion is less than target, the Absolute Total Shareholder Return portion will be deemed not to exceed target level performance.

William J. Way, President and Chief Executive Officer, was granted 803,580 of each type of award; Julian M. Bott, Executive Vice President and Chief Financial Officer, was granted 297,620 of each type of award; J. David Cecil, Executive Vice President, Corporate Development was granted 327,390 of each type of award; John C. Ale, Senior Vice President, General Counsel and Secretary, was granted 210,720 of each type of unit award; and Jennifer E. Stewart, Senior Vice President, Government and Regulatory Affairs, was granted 65,840 of each type of unit award.

There was no additional information required to be disclosed in a current report on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2018, that was not reported on such form.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The definitive proxy statement to holders of the Company's common stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Stockholders to be held on or about May 21, 2019 (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 2019 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 Business Conduct Guidelines that apply to its Chief Executive Officer, Chief Financial Officer and Controller as well as other officers and employees. We have posted a copy of our Business Conduct Guidelines 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 2019 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 21, 2019, 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 2019 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 21, 2019, 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 2019 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 21, 2019, 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 2019 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before May 21, 2019, 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 2019 Proxy Statement is not deemed to be a part of this Annual Report 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 28, 2019	SOUTHWESTERN ENERGY COMPANY By: /s/ JULIAN M. BOTT Julian M. Bott Executive 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 28, 2019, 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/ JULIAN M. BOTT Julian M. Bott	Executive 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 KEHR Catherine Kehr	Director
/s/ GREG D. KERLEY Greg D. Kerley	Director
/s/ GARY P. LUQUETTE Gary P. Luquette	Director
/s/ JON A. MARSHALL Jon A. Marshall	Director
/s/ PATRICK M. PREVOST Patrick M. Prevost	Director
/s/ TERRY W. RATHERT Terry W. Rathert	Director
/s/ ANNE TAYLOR Anne Taylor	Director

EXHIBIT INDEX

Exhibit Number	Description
2.1	Membership Interest Purchase Agreement dated as of August 30, 2018 between Southwestern Energy Company and Flywheel Energy Operating, LLC (Incorporated by reference to Exhibit 2.1 to the Registrant’s Current Report on Form 8-K filed on September 4, 2018)
2.2	Closing Agreement and First Amendment to Membership Interest Purchase Agreement dated as of December 3, 2018 between Southwestern Energy Company and Flywheel Energy Operating, LLC (Incorporated by reference to Exhibit 2.1 to the Registrant’s Current Report on Form 8-K filed on December 4, 2018)
3.1	Amended and Restated Certificate of Incorporation of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.1 to the Registrant’s Current Report on Form 8-K filed May 24, 2010)
3.2	Amended and Restated Bylaws of Southwestern Energy Company, as amended on April 25, 2017. (Incorporated by reference to Exhibit 3.1 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2017)
3.3	Certificate of Designations of 6.25% Series B Mandatory Convertible Preferred Stock (including form of stock certificate). (Incorporated by reference to Exhibit 3.1 to the Registrant’s Current Report on Form 8-K filed on January 21, 2015)
3.4	Certificate of Designation, Preferences and Rights of Series A Junior Participating Preferred Stock, dated April 9, 2009. (Incorporated by reference to Exhibit 3.1 to the Registrant’s Current Report on Form 8-K filed on April 9, 2009)
4.1	Form of Common Stock Certificate. (Incorporated by reference to Exhibit 4.4 to the Registrant’s Current Report on Form 8-K/A filed August 3, 2006)
4.2	Policy on Confidential Voting of Southwestern Energy Company. (Incorporated by reference to the Appendix of the Registrant’s Definitive Proxy Statement (Commission File No. 1-08246) for the 2006 Annual Meeting of Stockholders)
4.3	Indenture, dated as of December 1, 1995 between Southwestern Energy Company and The First National Bank of Chicago, as trustee. (Incorporated by reference to Exhibit 4 to Amendment No. 1 to the Registrant’s Registration Statement on Form S-3 (File No. 33-63895) filed on November 17, 1995)
4.4	First Supplemental Indenture between Southwestern Energy Company and J.P. Morgan Trust Company, N.A. (as successor to the First National Bank of Chicago) dated June 30, 2006. (Incorporated by reference to Exhibit 4.2 to the Registrant’s Current Report on Form 8-K/A filed August 3, 2006)
4.5	Second Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee (as successor to J.P. Morgan Trust Company, N.A.), dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K/A filed on May 8, 2008)
4.6	Indenture dated June 1, 1998 by and among NOARK Pipeline Finance, L.L.C. and The Bank of New York. (Incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed May 4, 2006)
4.7	First Supplemental Indenture dated May 2, 2006 by and among Southwestern Energy Company, NOARK Pipeline Finance, L.L.C., and UMB Bank, N.A., as trustee (as successor to the Bank of New York). (Incorporated by reference to Exhibit 4.2 to the Registrant’s Current Report on Form 8-K filed May 4, 2006)
4.8	Second Supplemental Indenture between Southwestern Energy Company and UMB Bank, N.A., as trustee, dated June 30, 2006. (Incorporated by reference to Exhibit 4.3 to the Registrant’s Current Report on Form 8-K/A filed August 3, 2006)
4.9	Third Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and UMB Bank, N.A., as trustee, dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.2 to the Registrant’s Current Report on Form 8-K/A filed on May 8, 2008)
4.10	Guaranty dated June 1, 1998 by Southwestern Energy Company in favor of The Bank of New York, as trustee, under the Indenture dated as of June 1, 1998 between NOARK Pipeline Finance L.L.C. and such trustee. (Incorporated by reference to Exhibit 4.6 to the Registrant’s Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2005)

4.11	Indenture dated January 16, 2008 among Southwestern Energy Company, the Guarantors named therein and The Bank of New York Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed January 16, 2008)
4.12	Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee, dated as of March 5, 2012. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed March 6, 2012)
4.13	First Supplemental Indenture, dated as of November 29, 2017 between Southwestern Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on December 1, 2017)
4.14	Second Supplemental Indenture, dated as of April 26, 2018 between Southwestern Energy Company, the guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)
4.15	Third Supplemental Indenture, dated as of September 17, 2018 between Southwestern Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on September 18, 2018)
4.16	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)
4.17	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)
4.18	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)
4.19	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)
4.20	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)
4.21	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)
4.22	Form of 4.95% Notes due 2025. (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K filed on January 23, 2015)
4.23	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)
4.24	Second Supplemental Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.25	Third Supplemental Indenture, dated as of November 29, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on December 1, 2017)
4.26	Fourth Supplemental Indenture, dated as of April 26, 2018 between Southwestern Energy Company, the guarantors named therein 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 April 26, 2018)
4.27	Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.28	First Supplemental Indenture, dated as of September 25, 2017 between Southwestern Energy Company and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.29	Second Supplemental Indenture, dated as of April 26, 2018 between Southwestern Energy Company, the guarantors named therein and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)

4.30	Form of 7.50% Notes due 2026. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
4.31	Form of 7.75% Notes due 2027. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K filed on September 25, 2017)
10.1	Form of Second Amended and Restated Indemnity Agreement between Southwestern Energy Company and each Executive Officer and Director of the Registrant. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
10.2	Form of Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company, effective February 17, 1999. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.3	Form of Amendment to Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company prior to 2011. (Incorporated by reference to Exhibit 10.3 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2008)
10.4	Form of Executive Severance Agreement between Southwestern Energy Company and Executive Officers Post 2011. (Incorporated by reference to Exhibit 10.4 to the Registrant's Annual Report on Form 10-K (Commission File No.1-08426) for the year ended December 31, 2011)
10.5	Southwestern Energy Company Supplemental Retirement Plan as amended. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on February 19, 2008)
10.6	Southwestern Energy Company Non-Qualified Retirement Plan as amended. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on February 19, 2008)
10.7	Amendment One to the Southwestern Energy Company Non-Qualified Retirement Plan (Incorporated by reference to Exhibit 10.9 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009)
10.8	Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Annex A of the Registrant's Proxy Statement filed April 8, 2013)
10.9	First Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 20, 2016)
10.10	Second Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 of the Registrant's Current Report on Form 8-K filed on May 30, 2017)
10.11	Southwestern Energy Company 2013 Incentive Plan Form of Performance Unit Award Agreement. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on March 8, 2018)
10.12	Southwestern Energy Company 2013 Incentive Plan Guidelines for Annual Incentive Awards. (Incorporated by reference to Exhibit 10.03 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.13	Southwestern Energy Company 2013 Incentive Plan Form of Incentive Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.04 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.14	Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement. (Incorporated by reference to Exhibit 10.05 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.15	Southwestern Energy Company 2013 Incentive Plan Form of Non-Qualified Stock Option Award Agreement for Directors. (Incorporated by reference to Exhibit 10.06 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.16	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement. (Incorporated by reference to Exhibit 10.07 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.17	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Award Agreement for Directors, as amended on May 23, 2017. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017)
10.18	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on March 8, 2018)

10.19	Southwestern Energy Company 2013 Incentive Plan Form of Restricted Stock Unit Award Agreement for Directors. (Incorporated by reference to Exhibit 10.10 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013)
10.20	Form of Incentive Stock Option for awards granted on or after December 8, 2005. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.21	Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2005 and through December 8, 2011 (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.22	Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2011. (Incorporated by reference to Exhibit 10.20 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08426) for the year ended December 31, 2011)
10.23	Guaranty by and between Southwestern Energy Company and Texas Gas Transmission, LLC, dated as of October 27, 2008. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q (Commission File No. 1-08246) for the period ended September 30, 2008)
10.24	Guaranty by and between Southwestern Energy Company and Fayetteville Express Pipeline, LLC dated September 30, 2008 (Incorporated by reference to Exhibit 10.22 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2009)
10.25	Retirement 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)
10.26	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)
10.27	Separation and Release Agreement dated August 23, 2017 between Southwestern Energy Company and Mark K. Boling. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
10.28	Amendment to Awards Agreement dated August 23, 2017 between Southwestern Energy Company and Mark K. Boling. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
10.29*	Retirement Agreement dated December 20, 2018 between Southwestern Energy Company and John E. "Jack" Bergeron, Jr.
10.30*	Amendment to Awards Agreement dated December 20, 2018 between Southwestern Energy Company and John E. "Jack" Bergeron, Jr.
10.31	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)
10.32	Amendment No. 1 to Credit Agreement, dated as of June 27, 2016 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
10.33	Amendment No. 1 to Credit Agreement, dated as of September 11, 2017 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as administrative agent, and each lender from time to time party thereto. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on September 11, 2017)
10.34	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)
10.35	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)
10.36	Credit Agreement, dated as of April 26, 2018 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 10.1 to the Registrant's Current Report on Form 8-K filed on April 26, 2018)

10.37	Amendment No. 1 to Credit Agreement, dated as of April 26, 2018 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed on October 25, 2018)
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 16, 2019
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 2018 Form 10-K.

Certifications

In 2018, 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 2018.

Annual Meeting
May 21, 2019 at 9:00 a.m. CDT
Southwestern Energy Company
10000 Energy Drive
Spring, TX 77389-4954

Independent Registered Public Accountants
PricewaterhouseCoopers LLP
Houston, TX

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Corporate Headquarters
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832.796.4700

Non-GAAP Reconciliations

Adjusted Diluted Earnings (Loss) Per Share

	2018	2017	2016
Diluted earnings (loss) per share	**$ 0.93**	$ 1.63	$ (6.32)
Add back:			
Participating securities–mandatory convertible preferred stock	**--**	0.18	--
Impairments	**0.30**	--	5.33
Restructuring and other one-time charges	**0.06**	--	0.20
Gain on sale of assets, net	**(0.03)**	(0.01)	--
(Gain) loss on certain derivatives	**0.04**	(0.90)	0.86
Loss on early extinguishment of debt and other bank fees	**0.03**	0.15	0.13
Legal settlement charges	**0.02**	0.01	--
Loss on foreign currency adjustment	**--**	0.01	--
Adjustments due to inventory valuation and other	**0.01**	(0.00)	0.01
Adjustments due to discrete tax items[1]	**(0.23)**	(0.91)	2.25
Tax impact on adjustments	**(0.11)**	0.28	(2.47)
Adjusted diluted earnings (loss) per share	**$ 1.02**	$ 0.44	$ (0.01)

[1] Primarily relates to the exclusion of certain discrete tax adjustments associated with the valuation allowance against deferred tax assets. The Company expects its 2018 income tax rate to be 24.5% before the impacts of any valuation allowance.

Net Cash Flow (in millions)

	2018	2017	2016
Net cash provided by operating activities	**$ 1,223**	$ 1,097	$ 498
Add back:			
Changes in operating assets and liabilities	**90**	41	99
Restructuring charges	**39**	--	48
Net cash flow	**$ 1,352**	$ 1,138	$ 645

Adjusted EBITDA (in millions)

	2018	2017	2016
Net income (loss)	**$ 537**	$ 1,046	$ (2,643)
Add back:			
Net interest expense	**124**	135	88
Income tax expense (benefit)	**1**	(93)	(29)
Depreciation, depletion and amortization	**560**	504	436
Impairments	**171**	--	2,321
Restructuring and other one-time charges	**39**	--	89
Gain on sale of assets, net	**(17)**	(4)	(3)
Loss on early extinguishment of debt and other bank fees	**17**	73	51
Legal settlement charges	**9**	5	--
(Gain) loss on certain derivatives	**24**	(451)	373
Loss on foreign currency adjustment	**--**	6	--
Adjustments due to inventory valuation and other	**3**	(2)	3
Stock-based compensation expense	**16**	28	35
Adjusted EBITDA	**$ 1,484**	$ 1,247	$ 721

Net Debt (in millions)

	2018	2017	2016
Total debt	**$ 2,318**	$ 4,391	$ 4,653
Subtract:			
Cash and cash equivalents	**(201)**	(916)	(1,423)
Net debt	**$ 2,117**	$ 3,475	$ 3,230

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

Southwestern Energy

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