RANGE RESOURCES CORP
Form 10-K
February 25, 2019
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark one)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number: 001-12209

RANGE RESOURCES CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

Delaware	34-1312571
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
100 Throckmorton Street, Suite 1200, Fort Worth, Texas	76102
(Address of Principal Executive Offices)	(Zip Code)

Registrant’s telephone number, including area code

(817) 870-2601

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of each exchange on which registered
Common Stock, $.01 par value	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 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	Smaller reporting company
Accelerated filer	Emerging growth company
Non-accelerated filer	

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 and non-voting common equity held by non-affiliates as of June 30, 2018 was $4,054,716,000. This amount is based on the closing price of registrant's common stock on the New York Stock Exchange on that date. Shares of common stock held by executive officers and directors of the registrant are not included in the computation. However, the registrant has made no determination that such individuals are "affiliates" within the meaning of Rule 405 of the Securities Act of 1933.

As of February 22, 2019, there were 250,161,892 shares of Range Resources Corporation Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement to be furnished to stockholders in connection with its 2019 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this report relates, are incorporated by reference in Part II, Item 5 and Part III, Items 10-14 of this report.

RANGE RESOURCES CORPORATION

Unless the context otherwise indicates, all references in this report to “Range,” “we,” “us” or “our” are to Range Resources Corporation and its directly and indirectly owned subsidiaries. Unless otherwise noted, all information in the report relating to natural gas, natural gas liquids and oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates and are net to our interest. If you are not familiar with the oil and gas terms used in this report, please refer to the explanation of such terms under the caption “Glossary of Certain Defined Terms” at the end of Items 1 & 2. Business and Properties of this report.

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PART I

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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended ("Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended ("Exchange Act"). These are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including without limitation: drilling plans, planned wells, rig count; our 2019 capital budget and the planned allocation thereof; reserve estimates; expectations regarding future economic and market conditions and their effects on us; our financial and operational outlook and ability to fulfill that outlook; and our financial position, balance sheet, liquidity and capital resources and the benefits thereof. These statements typically contain words such as "may," "anticipates," "believes," "estimates," "expects," "plans," "predicts," "targets," "projects," "shou similar words, indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

While we believe that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. For a description of known material factors that could cause our actual results to differ from those in the forward-looking statements, see other factors discussed in Item 1A. Risk Factors.

Actual results may vary significantly from those anticipated due to many factors, including:

- conditions in the oil and gas industry, including supply and demand levels for natural gas, crude oil and natural gas liquids ("NGLs") and the resulting impact on price;
- the availability and volatility of securities, capital or credit markets and the cost of capital to fund our operation and business strategy;
- accuracy and fluctuations in our reserves estimates due to regulations, reservoir performance or sustained low commodity prices;
- ability to develop existing reserves or acquire new reserves;
- drilling and operating risks;
- well production timing;
- changes in political or economic conditions in our key operating markets;
- prices and availability of goods and services, including third-party infrastructure;
- unforeseen hazards such as weather conditions, acts of war or terrorist acts;
- electronic, cyber or physical security breaches;
- changes in safety, health, environmental, tax and other regulations;
- other geological, operating and economic considerations;
- the ability and willingness of current or potential lenders, derivative contract counterparties, customers and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us; or
- other factors discussed in Items 1 and 2. Business and Properties, Item 1A. Risk Factors, Item 7. Management Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures about Market Risk and elsewhere in this report.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise except as required by law. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

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PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

Range Resources Corporation, a Delaware corporation, is a Fort Worth, Texas-based independent natural gas, NGLs and oil company, engaged in the exploration, development and acquisition of natural gas and oil properties in the United States. Our principal areas of operation are the Marcellus Shale in Pennsylvania and the Lower Cotton Valley formation in North Louisiana. Our corporate offices are located at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 (telephone (817) 870-2601). We also maintain field offices in our areas of operation. Our common stock is listed and trades on the New York Stock Exchange (the "NYSE") under the ticker symbol "RRC." Range Resources Corporation was incorporated in 1980. At December 31, 2018, we had 249.5 million shares outstanding.

Our 2018 production had the following characteristics:

- average total production of 2,201.1 Mmcfe per day, an increase of 10% from 2017;
- 68% natural gas;
- total natural gas production of 548.1 Bcf, an increase of 12% from 2017;
- total NGLs production of 38.3 Mmbbls (including ethane), an increase of 7% from 2017;
- total crude oil and condensate production of 4.2 Mmbbls, a decrease of 12% from 2017; and
- 85% of our total production was from the Marcellus Shale play in Pennsylvania.

At year-end 2018, our proved reserves had the following characteristics:

- 18.1 Tcfe of proved reserves;
- 67% natural gas, 31% NGLs and 2% crude oil;
- 54% proved developed;
- almost 100% operated;
- 94% of proved reserves are in the Marcellus Shale play in Pennsylvania;
- a reserve life index of approximately 23 years (based on fourth quarter 2018 production);
- a pretax present value of $13.2 billion of future net cash flows, discounted at 10% per annum ("PV-10"[a]); and
- a standardized after-tax measure of discounted future net cash flows of $11.1 billion.

(a) PV-10 is considered a non-GAAP financial measure as defined by the U.S. Securities and Exchange Commission (the "SEC"). We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and security analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of $2.1 billion at December 31, 2018.

Available Information

Our corporate website is available at http://www.rangeresources.com. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing we make with the SEC. We make available, free of charge, on our website, the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after filing such reports with the SEC. Other information such as presentations, our corporate responsibility culture, our Corporate Governance Guidelines, the charters of the Audit Committee, the Compensation

Committee, the Dividend Committee, the Governance and Nominating Committee, and the Code of Business Conduct and Ethics are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including the President and Chief Executive Officer and Chief Financial Officer.

The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Range, that file electronically with the SEC. The public can obtain any document we file with the SEC at http://www.sec.gov.

Our Business Strategy

Our overarching business objective is to build stockholder value through returns focused development, measured on a per share debt-adjusted basis, for both reserves and production. Our strategy to achieve our business objective is to increase reserves and production through internally generated drilling projects coupled with occasional acquisitions and divestitures of non-core assets. In addition, we expect to limit capital spending to at or below cash flow. Our strategy requires us to make significant investments and financial commitments in technical staff, acreage, seismic data, drilling and completion technology and gathering and transportation arrangements to build drilling inventory and market our products. Our strategy has the following key elements:

- commit to environmental protection and worker and community safety;
- concentrate in core operating areas;
- focus on cost efficiency;
- maintain a multi-year drilling inventory;
- maintain a long-life reserve base with a low base decline rate;
- market our products to a large number of customers in different markets under a variety of commercial terms;
- maintain operational and financial flexibility; and
- provide employee equity ownership and incentive compensation.

These elements are primarily anchored by our interests in the Marcellus Shale located in Pennsylvania. Complementing this growth area, we have natural gas, crude oil and condensate and NGLs production activities in the Lower Cotton Valley in North Louisiana.

Commit to Environmental Protection and Worker and Community Safety. We strive to implement technologies and commercial practices to minimize potential adverse impacts from the development of our properties on the environment, worker health and safety and the safety of the communities where we operate. We analyze and review performance while striving for continual improvement by working with peer companies, regulators, non-governmental organizations, industries not related to the oil and natural gas industry and other engaged stakeholders. We expect every employee to maintain safe operations, minimize environmental impact and conduct their daily business with the highest ethical standards.

Concentrate in Core Operating Areas. We currently operate primarily in two regions: Pennsylvania and North Louisiana. Concentrating our drilling and producing activities in these core areas allows us to develop the regional expertise needed to interpret specific geological and operating conditions and develop economies of scale. Operating in core areas as large as the Marcellus Shale and the Lower Cotton Valley allows us to pursue our goal of consistent production and reserve growth at attractive returns. We intend to further develop our acreage in both the Marcellus Shale and North Louisiana and improve our well results through the use of technology and detailed analysis of our properties. We periodically evaluate and pursue acquisition opportunities in the United States (including opportunities to acquire particular natural gas and oil properties or entities owning natural gas and oil assets) and at any given time we may be in various stages of evaluating such opportunities.

Focus on Cost Efficiency. We concentrate in areas which we believe to have sizeable hydrocarbon deposits in place that will allow us to economically grow production while controlling costs. Because there is little long-term competitive sales price advantage available to a commodity producer, the costs to find, develop, and produce a commodity are important to organizational sustainability and long-term stockholder value creation. We endeavor to control costs such that our cost to find, develop and produce natural gas, NGLs and oil is one of the lowest in the industry. We operate almost all of our total net production and believe that our extensive knowledge of the geologic and operating conditions in the areas where we operate provides us with the ability to achieve operational efficiencies.

Maintain a Multi-Year Drilling Inventory. We focus on areas with multiple prospective and productive horizons and development opportunities. We use our technical expertise to build and maintain a multi-year drilling inventory. We believe that a large, multi-year inventory of drilling projects increases our ability to efficiently plan for the economic growth of production and reserves. Currently, we have over 4,300 proven and unproven drilling locations in inventory.

Maintain a Long-Life Reserve Base with a Low Base Decline Rate. Long-life natural gas and oil reserves provide a more stable growth platform than short-life reserves. Long-life reserves reduce reinvestment risk as they lessen the amount of reinvestment capital deployed each year to replace production. Long-life natural gas and oil reserves also assist us in minimizing costs as stable production makes it easier to build and maintain operating economies of scale. Long-life reserves also offer upside from technology enhancements.

Market Our Products to A Large Number of Customers in Different Markets Under a Variety of Commercial Terms. We market our natural gas, NGLs, crude oil and condensate to a large number of customers in both domestic and international markets to maximize cash flow and diversify risk. We hold numerous firm transportation contracts on multiple pipelines to enable us to transport and sell natural gas and NGLs in the Midwest, Gulf Coast, Southeast, Northeast and international markets. We sell our products under a variety of price indexes and price formulas that assist us in optimizing regional price differentials and commodity price volatility.

Maintain Operational and Financial Flexibility. Because of the risks involved in drilling, coupled with changing commodity prices, we are flexible and adjust our capital budget throughout the year. If certain areas generate higher than anticipated returns, we may accelerate development in those areas and decrease expenditures elsewhere. We also believe in maintaining ample liquidity, using commodity derivatives to help stabilize our realized prices and focusing on financial discipline. We believe this provides more predictable cash flows and financial results. We regularly review our asset base to identify nonstrategic assets, the disposition of which will increase capital resources available for other activities and create organizational and operational efficiencies.

Provide Employee Equity Ownership and Incentive Compensation. We want our employees to think and act like business owners. To achieve this, we reward and encourage them through equity ownership in Range. All full-time employees are eligible to receive equity grants. As of December 31, 2018, our employees and directors owned equity securities in our benefit plans (vested and unvested) that had an aggregate market value of approximately $66.9 million.

Significant Accomplishments in 2018

- Proved reserves – Total proved reserves increased 18% in 2018, from 15.3 Tcfe to 18.1 Tcfe. This achievement is the result of continued drilling success. The Marcellus Shale is our largest producing region and contains our greatest concentration of reserves. While consistent growth is challenging to sustain, we believe the quality of our technical teams and our substantial inventory of high quality drilling locations provide the basis for future reserve and production growth. The pretax present value of future net cash flows (discounted at 10% per annum) increased to $13.2 billion in 2018 compared to $8.1 billion in 2017.
- Production growth – In 2018, our production averaged 2,201.1 Mmcfe per day, an increase of 10% from 2017. Drilling in the Marcellus Shale play in Pennsylvania drove our production growth. Our capital program is designed to allocate investments based on projects that maximize returns while minimizing controllable costs associated with production activities.
- Focus on financial flexibility – As of December 31, 2018, we maintained a $4.0 billion bank credit facility, with a borrowing base of $3.0 billion and committed borrowing capacity of $2.0 billion. We endeavor to maintain a strong liquidity position. In 2018, our total debt declined $271.9 million. Our 2018 capital budget, which was established at the beginning of the year, was $941.2 million with actual spending 3% lower. As we have done historically, we may adjust our capital program, divest of non-strategic assets and use derivatives to protect a portion of our future production from commodity price volatility to ensure adequate funds to execute our drilling program and maintain liquidity.
- Successful drilling program – In 2018, we drilled 104 gross natural gas and oil wells. We replaced 391% of our production through drilling in 2018 and our overall drilling success rate was 100%. We continue to build our drilling inventory which is critical to our ability to consistently drill wells each year on a cost effective and efficient basis. Controlling the costs to find, develop and produce natural gas, NGLs and oil is critical in creating long-term stockholder value. Our focus areas are characterized by large, contiguous acreage positions and multiple stacked geologic horizons. In 2018, we continued to reduce average well costs per foot drilled through faster drilling times, longer laterals and innovative completion optimizations.
- Large resource potential – Maintaining an exposure to large low-cost potential resources is important. We maintained and continued to develop our shale plays

in 2018. We have three large unconventional and prospective plays in Pennsylvania: the Marcellus, Utica and Upper Devonian shales. These plays cover expansive areas, provide multi-year drilling opportunities, are in many cases stacked pay and, collectively, have sustainable lower risk growth profiles. Similarly, our activity in North Louisiana also targets stacked pay.

- Dispositions completed – During 2018, we completed several divestitures. In third quarter 2018, we sold certain properties in Northern Oklahoma for proceeds of $23.3 million and we recorded a loss of $39,000 related to this sale, after closing adjustments. In fourth quarter 2018, we sold a proportionately reduced 1% overriding royalty in our Washington County, Pennsylvania leases for gross proceeds of $300.0 million and we recorded a loss of $10.2 million, after closing adjustments and transaction fees.

Industry Operating Environment

We operate entirely within the continental United States. The oil and natural gas industry is affected by many factors that we cannot control. Government regulations, particularly in the areas of taxation, energy, climate change and the environment, can have a significant impact on our operations and profitability. The impact of these factors is difficult to accurately predict or anticipate. It is difficult for us to predict the occurrence of events that may affect commodity prices or the degree to which these prices will be affected; however, the prices we receive for the commodities we produce will generally approximate current market prices in the geographic region of the production, not including the impact of our derivative program.

Significant factors that are likely to affect 2019 commodity prices include: the effect of new policies enacted by the President of the United States and his administration, fiscal challenges facing the United States federal government, expected economic growth throughout the world, forecasted increased demand from Asian and European markets, supply and demand fundamentals for NGLs in the United States and the pace at which export capacity grows, and the pace that gas storage is refilled during the year.

Natural gas prices are primarily determined by North American supply and demand and natural gas exports and is heavily influenced by weather and storage levels. The New York Mercantile Exchange (“NYMEX”) monthly settlement prices for natural gas averaged $3.07 per mcf in 2018, with a high of $4.72 per mcf in December and a low of $2.64 per mcf in March. In 2017, monthly NYMEX settlement prices averaged $3.10 per mcf. Since the end of 2018, natural gas prices have decreased, with the monthly settlement price for natural gas decreasing from $4.72 per mcf in December 2018 to $2.95 per mcf in February 2019. Natural gas prices may come under pressure largely due to an abundant supply of natural gas caused by the high productivity of shale plays in the United States which could continue to outpace demand.

Significant factors that will impact 2019 crude oil prices include worldwide economic conditions, the rate of production growth in the United States, political and economic developments in the Middle East, Africa and South America, demand in Asian and European markets and the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations choose to manage oil supply through export quotas. NYMEX monthly settlement prices for oil averaged $65.49 per barrel in 2018, with a high of $70.76 per barrel in October and a low of $48.98 per barrel in December. In 2017, NYMEX monthly settlement prices for oil averaged $51.07 per barrel. Since the end of 2018, crude oil prices have improved, with the monthly settlement price for crude oil rising from $48.98 per barrel in December 2018 to $51.55 per barrel in January 2019. The likelihood of a sustained recovery in worldwide demand for energy is difficult to predict. As a result, we expect crude oil commodity prices will continue to be volatile in 2019.

NGLs prices are primarily determined by North American supply and demand and to a lesser extent, international supply and demand. The growth of unconventional drilling has substantially increased the supply of NGLs, which until recently, caused a significant decline in NGLs component prices. Additional export facilities have been built and NGLs exports are increasing along with the expansion of ethane cracking capacity which has recently improved NGLs pricing in the United States. While NGLs component prices have improved in recent months, we expect prices will continue to be volatile in 2019.

Natural gas, NGLs and oil prices affect:

- our revenues, profitability and cash flow;
- the quantity of natural gas, NGLs and oil that we can economically produce;
- the quantity of natural gas, NGLs and oil shown as proved reserves;
- the amount of cash flow available to us for capital expenditures; and
- our ability to borrow and raise additional capital.

Continued or extended decline in natural gas, NGLs and oil prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we currently, and may in the future, use derivative instruments to hedge future sales prices on our natural gas, NGLs, crude oil and condensate production. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also partially protect us from declining price movements.

Segment and Geographical Information

Our operations consist of one reportable segment. We have a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Our exploration and production operations are limited to onshore United States.

Outlook for 2019

For 2019, we have established a $756.0 million capital budget for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. This budget is approximately 90% allocated to our Appalachian division and includes $684.8 million for drilling costs, $51.0 million for acreage, $12.0 million for pipelines and facilities and $8.2 million for other expenditures. As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices, drilling success and other factors. Throughout the year, we allocate capital on a project-by-project basis. We expect the 2019 capital expenditure program to be funded by internally generated cash flows. To the extent our 2019 capital requirements might exceed our internally generated cash flow, we may reduce the capital budget or use proceeds from asset sales, draw on our committed capacity under our bank credit facility, and/or debt or equity financing may be used to fund these requirements. The prices we receive for our natural gas, NGLs and oil production are largely based on current market prices, which are beyond our control. The price risk on a portion of our forecasted natural gas, NGLs and oil production for 2019 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions.

Our primary near-term focus includes the following:

- achieving competitive returns on investments;
- preserve liquidity and improve financial strength;
- focus on organic opportunities through disciplined capital investments;
- improve operational efficiencies and economic returns;
- limit capital spending to at or below cash flow; and
- attract and retain quality employees whose efforts and incentives are aligned with stockholders’ interests.

Production, Price and Cost History

The following table sets forth information regarding natural gas, NGLs and oil production, realized prices and production costs for the last three years. The price we receive is largely a function of market supply and demand. Historically, commodity prices have been volatile and we expect that volatility to continue in the future. For more information, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

	Year Ended December 31,		
	2018	2017	2016
Production			
Natural gas (Mmcf)	548,085	490,253	375,811
Natural gas liquids (Mbbls)	38,325	35,709	27,826
Crude oil and condensate (Mbbls)	4,228	4,787	3,609
Total (Mmcfe) [a]	803,408	733,231	564,420
Average sales prices (excluding derivative settlements)			
Natural gas (per mcf)	$3.04	$2.75	$2.01
Natural gas liquids (per bbl)	24.30	16.93	11.44
Crude oil and condensate (per bbl)	60.52	46.30	34.60
Total (per mcfe) [a]	3.55	2.97	2.12
Average realized prices (including all derivative settlements):			
Natural gas (per mcf)	$2.98	$2.90	$2.68
Natural gas liquids (per bbl)	22.62	14.88	13.16
Crude oil and condensate (per bbl)	51.60	49.49	47.82
Total (per mcfe) [a]	3.39	2.99	2.74

Average realized prices (including all derivative settlements and third-party transportation costs)			
Natural gas (per mcf)	$1.74	$1.82	$1.60
Natural gas liquids (per bbl)	11.15	8.32	7.33
Crude oil and condensate (per bbl)	51.60	49.49	47.82
Total (per mcfe) [a]	1.99	1.95	1.74
Direct operating costs			
Lease operating (per mcfe) [a]	$0.16	$0.17	$0.16
Workovers (per mcfe) [a]	0.01	0.01	0.01
Stock-based compensation (per mcfe) [a]	—	—	—
Total (per mcfe) [a]	$0.17	$0.18	$0.17

[a] Oil and NGLs are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

Proved Reserves

The following table sets forth our estimated proved reserves for years ended 2018, 2017 and 2016 based on the average of prices on the first day of each month of the given calendar year, in accordance with SEC rules. Oil includes both crude oil and condensate. We have no natural gas, NGLs or oil reserves from non-traditional sources. Additionally, we do not provide optional disclosures of probable or possible reserves.

	Summary of Oil and Gas Reserves as of Year-End Based on Average Prices				
Reserve Category	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe) [a]	%
2018:					
Proved					
Developed	6,451,012	512,318	38,658	9,756,870	54 %
Undeveloped	5,576,690	409,276	47,198	8,315,536	46 %
Total Proved	12,027,702	921,594	85,856	18,072,406	100%
2017:					
Proved					
Developed	5,437,674	448,258	36,808	8,348,074	55 %
Undeveloped	4,825,975	315,006	33,046	6,914,287	45 %
Total Proved	10,263,649	763,264	69,854	15,262,361	100%
2016:					
Proved					
Developed	4,352,141	363,852	39,110	6,769,908	56 %
Undeveloped	3,518,275	266,214	31,143	5,302,414	44 %
Total Proved	7,870,416	630,066	70,253	12,072,322	100%

[a] Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

The following table sets forth summary information by area with respect to estimated proved reserves at December 31, 2018:

	Reserve Volumes					PV-10 [a]	
	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe)	%	Amount (In thousands)	%
Appalachian Region	11,207,409	882,966	76,886	16,966,517	94 %	$12,229,618	93 %
North Louisiana Region	820,096	38,628	8,955	1,105,596	6 %	943,252	7 %
Other	197	—	15	293	— %	623	— %
Total	12,027,702	921,594	85,856	18,072,406	100%	$13,173,493	100%

(a)

PV-10 was prepared using the twelve-month average prices for 2018, discounted at 10% per annum. Year-end PV-10 is a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. Our total standardized measure was $11.1 billion at December 31, 2018. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of $2.1 billion at December 31, 2018. Included in the $13.2 billion pretax PV-10 is $8.4 billion related to proved developed reserves.

Reserve Estimation

All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. We also had the following independent petroleum consultants conduct an audit of our year-end 2018 reserves: Wright & Company, Inc. (Appalachia) and Netherland, Sewell & Associates, Inc. (North Louisiana). The purpose of these audits was to provide additional assurance on the reasonableness of internally prepared reserve estimates. These engineering firms were selected for their geographic expertise and their historical experience in engineering certain properties. The proved reserve audits performed for 2018, 2017 and 2016, in the aggregate, represented 94%, 98% and 96% of our proved reserves. The reserve audits performed for 2018, 2017 and 2016, in the aggregate represented 96%, 98% and 96% of our 2018, 2017 and 2016 associated pretax present value of proved reserves discounted at ten percent. Copies of the summary reserve reports prepared by our independent petroleum consultants are included as an exhibit to this Annual Report on Form 10-K. The technical person at each independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultants to ensure the integrity, accuracy and timeliness of data furnished during the reserve audit process. Throughout the year, our technical team meets periodically with representatives of our independent petroleum consultants to review properties and discuss methods and assumptions. While we have no formal committee specifically designated to review reserves reporting and the reserve estimation process, our senior management reviews and approves significant changes to our proved reserves. We provide historical information to our consultants for our largest producing properties such as ownership interest, natural gas, NGLs and oil production, well test data, commodity prices and operating and development costs. Our consultants perform an independent analysis and differences are reviewed with our Senior Vice President of Reservoir Engineering and Economics. In some cases, additional meetings are held to review identified reserve differences. The reserve auditor estimates of proved reserves and the pretax present value of such reserves discounted at 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared on a lease-by-lease, field-by-field or area-by-area basis, some of our estimates may be greater than those of our auditor and some may be less than the estimates of the reserve auditors. When such differences do not exceed 10% in the aggregate, our reserve auditors are satisfied that the proved reserves and pretax present value of such reserves discounted at 10% are reasonable and will issue an unqualified opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analysis.

Historical variances between our reserve estimates and the aggregate estimates of our independent petroleum consultants have been less than 5%. All of our reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, Mr. Alan Farquharson, who reports directly to our President and Chief Executive Officer. Our Senior Vice President of Reservoir Engineering and Economics holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University. Before joining Range, he held various technical and managerial positions with Amoco, Hunt Oil and Union Pacific Resources and has more than thirty-five years of engineering experience in the oil and gas industry. During the year, our reserves group may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions. We did not file any reports during the year ended December 31, 2018 with any federal authority or agency with respect to our estimate of natural gas and oil reserves.

Reserve Technologies

Proved reserves are those quantities of natural gas, NGLs and oil 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. The term "reasonable certainty" implies a high degree of confidence that the quantities of natural gas, NGLs and oil actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal technical staff employs technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, empirical evidence through drilling results and well performance, decline curve analysis, well logs, geologic maps and available downhole and production data, seismic data, well test data, reservoir simulation modeling and implementation and application of enhanced data analytics.

Reporting of Natural Gas Liquids

We produce NGLs as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. At December 31, 2018, NGLs represented approximately 31% of our total proved reserves on an mcf equivalent basis. NGLs are products priced by the gallon (and sold by the barrel) to the customer. In reporting proved reserves and production of NGLs, we have included production and reserves in barrels. Prices for a barrel of NGLs in 2018 averaged approximately 40% of the average price for equivalent volumes of oil. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs. As of December 31, 2018, we have 468.9 Mmbbls of ethane reserves (2,075 Bcfe) associated with our Marcellus Shale properties, which are included in NGLs proved reserves and represent 51% of our total NGLs reserves. We currently include ethane in our proved reserves which match volumes to be delivered under our existing long-term, extendable ethane contracts.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2018, our PUDs totaled 47.2 Mmbbls of crude oil, 409.3 Mmbbls of NGLs and 5.6 Tcf of natural gas, for a total of 8.3 Tcfe. Costs incurred in 2018 relating to the development of PUDs were approximately $623 million. Approximately 95% of our PUDs at year-end 2018 were associated with the Marcellus Shale. All PUD drilling locations are scheduled to be drilled prior to the end of 2023. As of December 31, 2018, we have no reserves that have been reported for more than five years from their original booking. Changes in PUDs that occurred during the year were due to:

- conversion of approximately 1.8 Tcfe of PUDs into proved developed reserves;
- addition of new PUDs from drilling consisting of 2.7 Tcfe;
- 608 Bcfe net positive revision with 379 Bcfe of reserves reclassified to unproved because of previously planned wells not to be drilled within the original five-year development horizon more than offset by improved recovery and other positive performance revisions of 987 Bcfe; and
- 128 Bcfe reduction from the sale of properties.

For an additional description of changes in PUDs for 2018, see Note 19 to our consolidated financial statements. We believe our PUDs reclassified to unproved can be included in our future proved reserves as these locations are added back into our five-year development plan.

Proved Reserves (PV-10)

The following table sets forth the estimated future net cash flows, excluding open derivative contracts, from proved reserves, the present value of those net cash flows discounted at a rate of 10% (PV-10), and the expected benchmark prices and average field prices used in projecting net cash flows over the past five years. Our reserve estimates do not include any probable or possible reserves (in millions, except prices):

	2018	2017	2016	2015	2014
Future net cash flows	$34,836	$21,469	$10,301	$8,666	$26,993
Present value:					
Before income tax	13,173	8,147	3,727	3,029	10,070
After income tax (Standardized Measure)	11,116	7,165	3,452	2,726	7,593
Benchmark prices (NYMEX):					
Gas price (per mcf)	3.10	2.98	2.48	2.59	4.35
Oil price (per bbl)	65.55	51.19	42.68	50.13	94.42
Wellhead prices:					
Gas price (per mcf)	2.98	2.60	2.07	2.07	4.14
Oil price (per bbl)	59.96	45.73	37.41	35.07	79.04
NGLs price (per bbl)	25.22	17.84	13.44	11.74	27.20

Future net cash flows represent projected revenues from the sale of proved reserves, net of production and development costs (including transportation and gathering expenses, operating expenses and production taxes). Revenues are based on a twelve-month unweighted average of the first day of the month pricing, without escalation. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current economic conditions at each year-end. There can be no assurance that the proved reserves will be produced in the future or that prices, production or development costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Property Overview

Currently, our natural gas and oil operations are concentrated in the Appalachian and North Louisiana regions of the United States, primarily in the Marcellus Shale in Pennsylvania and the Lower Cotton Valley formation in Louisiana. Our North Louisiana properties were acquired in September 2016. Our properties consist of interests in developed and undeveloped natural gas and oil leases. These interests entitle us to drill for and produce natural gas, NGLs, crude oil and condensate from specific areas. Our interests are mostly in the form of working interests and, to a lesser extent, royalty and overriding royalty interests. We have a single company-wide management team that administers all properties as a whole. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. The table below summarizes our operating data for the year ended December 31, 2018.

Region	Average Daily Production (mcfe per day)	Production (Mmcfe)	Percentage of Production	Proved Reserves (Mmcfe)	Percentage of Proved Reserves
Appalachian	1,891,896	690,542	86 %	16,966,517	94 %
North Louisiana	303,077	110,623	14 %	1,105,596	6 %
Other	6,144	2,243	— %	293	— %
Total	2,201,117	803,408	100 %	18,072,406	100 %

The following table summarizes our costs incurred for the year ended December 31, 2018 (in thousands):

Region	Acreage Purchases	Acquisitions	Development Costs	Exploration Costs	Gathering Facilities	Asset Retirement Obligations	Total
Appalachian	$49,569	$1,683	$706,639	$32,043	$7,505	$28,697	$826,136
North Louisiana	12,858	—	127,970	3,453	3,218	579	148,078
Other	(37)	—	(57)	1	(505)	(450)	(1,048)
Total costs incurred	$62,390	$ 1,683	$834,552	$35,497	$10,218	$28,826	$973,166

Approximately 94% of our proved reserves at December 31, 2018 is located in the Marcellus Shale in our Appalachian region. This play has a large portfolio of drilling opportunities and therefore has a significant unbooked resource potential within the Marcellus, Utica and Upper Devonian formations. The following table sets forth annual production volumes, average sales prices and production cost data for our wells in the Marcellus Shale play which, as of December 31, 2018, is our only field in which reserves are greater than 15% of our total proved reserves.

	Marcellus Shale 2018	2017	2016
Production:			
Natural gas (Mmcf)	458,406	377,096	327,000
NGLs (Mbbls)	34,181	29,972	25,666
Crude oil and condensate (Mbbls)	3,452	3,407	2,783
Total Mmcfe [(a)]	684,205	577,368	497,697
Sales Prices: [(b)]			
Natural gas (per mcf)	$ 1.77	$ 1.55	$0.79
NGLs (per bbl)	13.08	9.70	5.00
Crude oil and condensate (per bbl)	59.76	45.49	32.24
Total (per mcfe)	2.14	1.79	0.96
Production Costs:			
Lease operating (per mcfe)	$0.11	$0.10	$0.11
Production and ad valorem tax (per mcfe) [(c)]	0.05	0.05	0.05

(a) Oil and NGLs are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

(b) We do not record derivatives or the results of derivatives at the field level. Includes deductions for third-party transportation, gathering and compression expense.

(c) Includes Pennsylvania impact fee.

Appalachian Region

Our properties in this area are located in the Appalachian Basin in the northeastern United States, predominantly in Pennsylvania. Currently, our reserves are primarily in the Marcellus Shale formation but also include the Utica, Upper Devonian and Medina formations which principally produce at depths ranging from 3,500 feet to 11,500 feet. We own 4,900 net producing wells, almost all of which we operate. Our average working interest in this region is 97%. As of December 31, 2018, we have approximately 938,000 gross (878,000 net) acres under lease.

Reserves at December 31, 2018 were 17.0 Tcfe, an increase of 3.1 Tcfe, or 22%, from 2017. Drilling additions of 3.0 Tcfe, favorable reserve revisions for performance of 1.1 Tcfe, improved recovery and positive pricing revisions were partially offset by production, downward revisions for proved undeveloped reserves no longer in our current five-year development plan of 378.8 Bcfe and sales of 143.6 Bcfe. Annual production increased 18% from 2017. During 2018, we spent $706.6 million in this region to drill 90.0 (89.7 net) development wells, all of which were productive. At December 31, 2018, the Appalachian region had an inventory of over 400 proven drilling locations and 2 proven recompletions. During the year, the Appalachian region drilled 92 proven locations, added 198 new proven drilling locations and deleted or sold 27 proven drilling locations with deleted reserves reclassified to unproved because of longer laterals and lower future capital spending in response to lower commodity prices. During the year, the region achieved a 100% drilling success rate.

Marcellus Shale

We began operations in the Marcellus Shale in Pennsylvania during 2004. The Marcellus Shale is an unconventional reservoir, which produces natural gas, NGLs and condensate. This has been our largest investment area over the last ten years and we continue to pursue initiatives to improve drilling and completion efficiencies and reduce costs. We had over 400 proven drilling locations at December 31, 2018. Our 2018 production from the Marcellus Shale increased 18% from 2017. During 2018, we drilled 90.0 (89.7 net) development wells, all of which were successful. During 2018, we had approximately five drilling rigs in the field and expect to run an average of three rigs throughout 2019.

We have long-term agreements with third parties to provide gathering and processing services and infrastructure assets in the Marcellus Shale, which includes gathering and residue gas pipelines, compression, cryogenic processing, de-ethanization and NGL fractionation. We have an ethane sales contract in southwestern Pennsylvania whereby a third party purchases and transports ethane from the tailgate of third-party processing and fractionation facilities to the international border for further deliveries into Canada. We also have agreements to transport ethane to the Gulf Coast.

In 2012, we entered into a fifteen-year agreement to transport ethane and propane from the tailgate of a third-party processing plant to a terminal and dock facility near Philadelphia for sale to domestic and international customers. Also in 2012, we executed a fifteen-year agreement relating to ethane sales from that same terminal near Philadelphia. Propane and ethane operations from the terminal began in early 2016.

North Louisiana

We began operations in North Louisiana in September 2016 as a result of our acquisition of Memorial Resource Development Corp. (the “MRD Merger” or “Memorial”). These operations are focused on stacked-pay zones in Northern Louisiana, including the Lower Cotton Valley. The Lower Cotton Valley formation extends across East Texas, Louisiana and Southern Arkansas. The formation has been under development since the 1930s and is characterized by thick, multi-zone natural gas and oil reservoirs with well-known geologic characteristics and long-lived, predictable production profiles. We own 415 net producing wells in these locations, almost all of which we operate. Our average working interest is 72%. As of December 31, 2018, we have approximately 138,000 gross (118,000 net) acres under lease.

Total proved reserves were 1.1 Tcfe at December 31, 2018, a decrease of 11% from 2017. At December 31, 2018, this area had a development inventory of over 50 proven drilling locations and over 40 proven recompletions. We spent $128.0 million in this region to drill 14.0 (12.0 net) development wells, all of which were productive. Our operational focus in North Louisiana will be on a horizontal development drilling program that targets stacked pay zones. In 2018, we had approximately one drilling rig in the field and we expect to run an average of less than one rig throughout 2019.

We have long-term agreements with third parties to provide gathering, processing and transportation services and infrastructure assets in North Louisiana. We have entered into an area of mutual interest and exclusivity agreement with one of these parties whereby they have the exclusive right to provide midstream services to support our current and future production within such area.

Divestitures

Over the last three years, we have divested over $590.8 million of non-strategic assets in order to increase capital resources available for other activities, reduce our unit cost structure, create organizational and operating efficiencies and increase financial flexibility. In 2018, we sold the following assets:

Pennsylvania. In fourth quarter 2018, we sold a proportionately reduced 1% overriding royalty in our Washington County, Pennsylvania leases for proceeds of $300.0 million.

Northern Oklahoma. In third quarter 2018, we sold certain properties in Northern Oklahoma for proceeds of $23.3 million.

Miscellaneous. During the year ended December 31, 2018, we sold miscellaneous unproved property, inventory and other assets for proceeds of $1.2 million.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2018. If we own both a royalty and a working interest in a well, such interest is included in the table below. Wells are classified as natural gas or crude oil according to their predominant production stream. We do not have a significant number of dual completions.

	Total Wells		Average Working Interest
	Gross	Net	
Natural gas	5,650	5,325	94%
Crude oil	33	32	97%
Total	5,683	5,357	94%

Production wells are producing wells and wells mechanically capable of production. The day-to-day operations of natural gas and oil properties are the responsibility of the operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. An operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

Drilling Activity

The following table summarizes drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. This information should not be indicative of future performance nor should it be assumed that there was any correlation between the number of productive wells and the natural gas and oil reserves generated thereby. As of December 31, 2018, we had 156.0 gross (154.0 net) wells in the process of drilling or active completions stage. In addition, there are 3.0 gross (3.0 net) wells waiting on completion or waiting on pipelines at year-end 2018.

	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	104.0	101.7	176.0	163.5	107.0	100.9
Dry	—	—	—	—	—	—
Exploratory wells						
Productive	—	—	—	—	1.0	1.0
Dry	—	—	1.0	1.0	—	—
Total wells						
Productive	104.0	101.7	176.0	163.5	108.0	101.9
Dry	—	—	1.0	1.0	—	—
Total	104.0	101.7	177.0	164.5	108.0	101.9
Success ratio	100 %	100 %	99 %	99 %	100 %	100 %

Gross and Net Acreage

We own interests in developed and undeveloped natural gas and oil acreage. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying terms. Developed acreage includes leased acreage that is allocated or assignable to producing wells or wells capable of production even though shallower or deeper horizons may not have been fully explored. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not the acreage contains proved reserves. The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2018. Acreage related to option acreage, royalty, overriding royalty and other similar interests is excluded from this summary:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	92,098	73,738	45,971	43,890	138,069	117,628
New York	—	—	2,265	567	2,265	567
Oklahoma	13,811	9,040	—	—	13,811	9,040
Pennsylvania	837,990	784,462	91,407	87,829	929,397	872,291
Texas	800	800	—	—	800	800
West Virginia	5,877	5,196	—	—	5,877	5,196
Wyoming	—	—	12,468	9,952	12,468	9,952
	950,576	873,236	152,111	142,238	1,102,687	1,015,474
Average working interest		92 %		94 %		92 %

Undeveloped Acreage Expirations

The table below summarizes by year our undeveloped acreage scheduled to expire in the next five years. Over 35% of the acres scheduled to expire in 2019 are in North Louisiana.

	Acres		% of Total
As of December 31,	Gross	Net	Undeveloped
2019	30,976	29,401	21%
2020	25,117	23,398	16%
2021	46,118	42,658	30%
2022	16,621	16,483	12%
2023	18,768	18,306	13%

In all cases the drilling of a commercial well will hold acreage beyond the lease expiration date. We have leased acreage that is subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. However, we have in the past been able, and expect in the future to be able, to extend the lease terms of some of these leases and sell or exchange some of these leases with other companies. The expirations included in the table above do not take into account the fact that we may be able to extend the lease terms. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire and we expect to allow additional acreage to expire in the future. We currently have no proved undeveloped reserve locations scheduled to be drilled after lease expiration.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use, or affect the value, of the properties. Burdens on properties may include:

- customary royalty or overriding royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; or
- net profit interests.

Delivery Commitments

For a discussion of our delivery commitments, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Delivery Commitments.

Employees

As of January 1, 2019, we had 796 full-time employees. All full-time employees are eligible to receive equity awards approved by the compensation committee of the board of directors. No employees are currently covered by a labor union or other collective bargaining arrangement. We believe that the relationship with our employees is excellent.

Executive Officers of the Registrant

The executive officers of Range Resources and their ages as of February 1, 2019, are as follows:

	Age	Position
Jeffrey L. Ventura	61	Chief Executive Officer and President
Dennis L. Degner	46	Senior Vice President of Operations
Dori A. Ginn	61	Senior Vice President – Controller and Principal Accounting Officer
David P. Poole	56	Senior Vice President General Counsel; Corporate Secretary
Mark S. Scucchi	41	Senior Vice President – Chief Financial Officer

Jeffrey L. Ventura, chief executive officer and president, joined Range in 2003 as chief operating officer and became a director in 2005. Mr. Ventura was named President, effective May 2008 and Chief Executive Officer effective January 2012. Previously, Mr. Ventura served as president and chief operating officer of Matador Petroleum Corporation which he joined in 1997. Prior to his service at Matador, Mr. Ventura spent eight years at Maxus Energy Corporation where he managed various engineering, exploration and development operations and was responsible for coordination of engineering technology. Previously, Mr. Ventura was with Tenneco Oil Exploration and Production, where he held various engineering and operating positions. Mr. Ventura holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering from the Pennsylvania State University. Mr. Ventura is a member of the Society of Petroleum Engineers, American Association of Petroleum Geologists, the National Petroleum Council and the Texas Society of Professional Engineers.

Dennis L. Degner, senior vice president of operations, joined Range in 2010. Previously, Mr. Degner served as vice president of Appalachia. Mr. Degner is responsible for managing operations in both Appalachia and North Louisiana divisions. Mr. Degner has more than 20 years of oil and gas experience having worked in a variety of technical and managerial positions across the United States including Texas, Louisiana, Wyoming, Colorado and Pennsylvania. Prior to joining Range, Mr. Degner held positions with EnCana, Sierra Engineering and Halliburton. Mr. Degner is a member of the Society of Petroleum Engineers. Mr. Degner holds a Bachelor of Science Degree in Agricultural Engineering from Texas A&M University.

Dori A. Ginn, senior vice president – controller and principal accounting officer, joined Range in 2001. Ms. Ginn has held the positions of financial reporting manager, vice president and controller before being elected to principal accounting officer in September 2009. Prior to joining Range, she held various accounting positions with Doskocil Manufacturing Company and Texas Oil and Gas Corporation. Ms. Ginn received a Bachelor of Business Administration in Accounting from the University of Texas at Arlington. She is a certified public accountant.

David P. Poole, senior vice president – general counsel and corporate secretary, joined Range in June 2008. Mr. Poole has over 30 years of legal experience. From May 2004 until March 2008 he was with TXU Corp., serving last as executive vice president – legal, and general counsel. Prior to joining TXU, Mr. Poole spent 16 years with Hunton &

Williams LLP and its predecessor, where he was a partner and last served as the managing partner of the Dallas office. Mr. Poole graduated from Texas Tech University with a B.S. in Petroleum Engineering and received a J.D. magna cum laude from Texas Tech University School of Law.

Mark S. Scucchi, senior vice president – chief financial officer. Mr. Scucchi joined Range in 2008. Previously, Mr. Scucchi served as vice president – finance & treasurer. Prior to joining Range, Mr. Scucchi was with JPMorgan Securities providing commercial and investment banking services to small and mid-cap technology companies. Before joining JPMorgan Securities, Mr. Scucchi spent a number of years at Ernst & Young LLP in the audit practice. Mr. Scucchi earned a Bachelor of Science in Business Administration from Georgetown University and a Master of Science in Accountancy from the University of Notre Dame. Mr. Scucchi is a CFA Charterholder and a licensed CPA in the state of Texas.

Competition

Competition exists in all sectors of the oil and gas industry and in particular, we encounter substantial competition in developing and acquiring natural gas and oil properties, securing and retaining personnel, conducting drilling and field operations and marketing production. Competitors in exploration, development, acquisitions and production include the major oil and gas companies as well as numerous independent oil and gas companies, individual proprietors and others. Although our sizable acreage position and core area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources allow. We face competition for pipeline and other services to transport our product to markets, particularly in the Northeastern portion of the United States. Competitive advantage is gained in the oil and gas exploration and development industry by employing well-trained and experienced personnel who make prudent capital investment decisions based on management direction, embrace technological innovation and are focused on price and cost management. We have a team of dedicated employees who represent the professional disciplines and sciences that we believe are necessary to allow us to maximize the long-term profitability and net asset value inherent in our physical assets. For more information, see Item 1A. Risk Factors.

Marketing and Customers

We market the majority of our natural gas, NGLs, crude oil and condensate production from the properties we operate for our interest, and that of the other working interest owners. We pay our royalty owners from the sales attributable to our working interest. Natural gas, NGLs and oil purchasers are selected on the basis of price, credit quality and service reliability. For a summary of purchasers of our natural gas, NGLs and oil production that accounted for 10% or more of consolidated revenue, see Note 2 to our consolidated financial statements. Because alternative purchasers of natural gas and oil are usually readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on our operations. Production from our properties is marketed using methods that are consistent with industry practice. Sales prices for natural gas, NGLs and oil production are negotiated based on factors normally considered in the industry, such as index or spot price, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions. Our natural gas production is sold to utilities, marketing and midstream companies and industrial users. Our NGLs production is typically sold to petrochemical end users (both domestically and internationally) and, to a lesser extent, NGLs distributors and natural gas processors. Our oil and condensate production is sold to crude oil processors, transporters and refining and marketing companies in the area. Market volatility due to fluctuating weather conditions, international political developments, overall energy supply and demand, economic growth rates and other factors in the United States and worldwide have had, and will continue to have, a significant effect on energy prices.

We enter into derivative transactions with unaffiliated third parties for a varying portion of our production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in natural gas, NGLs and oil prices. For a more detailed discussion, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We incur gathering and transportation expense to move our production from the wellhead, tanks and processing plants to purchaser-specified delivery points. These expenses vary and are primarily based on volume, distance shipped and the fee charged by the third-party gatherers and transporters. We also have contracts based on percent of proceeds. Transportation capacity on these gathering and transportation systems and pipelines is occasionally constrained. Our Appalachian production is transported on third-party pipelines on which, in most cases, we hold long-term contractual capacity. We attempt to balance sales, storage and transportation positions, which can include purchase of commodities from third parties for resale, to satisfy transportation commitments. In Louisiana, we sell substantially all of our production, which is transported on third-party pipelines, to a variety of purchasers. We also have entered into gas processing agreements that have volumetric requirements.

We have not experienced significant difficulty to date in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to transport and market all of our production or obtain favorable prices.

We have entered into several ethane agreements to sell or transport ethane from our Marcellus Shale area. Initial deliveries commenced in late 2013 and deliveries under our most recent agreement began in early 2016. For more information, see Item 1A. Risk Factors – Our business depends on natural gas and oil transportation and NGLs processing facilities, most of which are owned by others and we rely on our ability to contract with those parties.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas and propane decreases during the spring and fall months and increases during the winter months and, in some areas, also increases during the summer months. Seasonal anomalies such as mild winters or hot summers also may impact this demand. In addition, pipelines, utilities, local distribution companies and industrial end-users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also impact the seasonality of demand.

Markets

Our ability to produce and market oil, NGLs and natural gas profitably depends on numerous factors beyond our control. The effect of these factors cannot be accurately predicted or anticipated. Although we cannot predict the occurrence of events that may affect commodity prices or the degree to which commodity prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production.

Governmental Regulation

Enterprises that sell securities in public markets are subject to regulatory oversight by federal agencies such as the SEC. The NYSE, a private stock exchange, also requires us to comply with listing requirements for our common stock. This regulatory oversight imposes on us the responsibility for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting, and ensuring that the financial statements and other information included in submissions to the SEC do not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made in such submissions not misleading. Failure to comply with the NYSE listing rules and regulations of the SEC could subject us to litigation from public or private plaintiffs. Failure to comply with the rules of the NYSE could result in the de-listing of our common stock, which could have an adverse effect on the market price of our common stock. Compliance with some of these rules and regulations is costly and regulations are subject to change or reinterpretation.

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state and local regulations, mandates and trade agreements. Governmental policies affecting the energy industry, such as taxes, tariffs, duties, price controls, subsidies, incentives, foreign exchange rates and import and export restrictions, can influence the viability and volume of production of certain commodities, the volume and types of imports and exports, whether unprocessed or processed commodity products are traded, and industry profitability. For example, the decision of the United States government to impose tariffs on certain Chinese imports and the resulting retaliation by the Chinese government imposing a 10 percent tariff on Unites States' liquefied natural gas exports have disrupted certain aspects of the energy market. Disruption of this sort can affect the price of oil and natural gas and may cause us to change our plans for exploration and production levels. Moreover, as a result of the 2018 mid-term elections, the United States Congress is now politically split, with a Democratic majority in the House of Representatives and a Republican majority in the Senate. It is too soon to determine what effect, if any, this split Congress will have on our operations. An overview of relevant federal, state and local regulations is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations, and the continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur, or past non-compliance with environmental laws or regulations may be discovered. See Item 1A. Risk Factors – The natural gas and oil industry is subject to extensive regulation. We do not believe we are affected differently by these regulations than others in the industry.

General Overview. Our oil and gas operations are subject to various federal, state and local laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- leases;
- acquisition of seismic data;
- location of wells, pads, roads, impoundments, facilities, rights of way;

- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and gas properties;
- drilling, casing and completion of wells;
- issuance of permits in connection with exploration, drilling, production, gathering, processing and transportation;
- well production, maintenance, operations and security;
- spill prevention and containment plans;
- emissions permitting or limitations;
- protection of endangered species;

- use, transportation, storage and disposal of hazardous waste, fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells;
- hydraulic fracturing;
- water withdrawal;
- operation of underground injection wells to dispose of produced water and other liquids;
- the marketing of production;
- transportation of production; and
- health and safety of employees and contract service providers.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act ("NGA") to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as Range, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission (the "FERC"), in contravention of rules prescribed by the FERC. In January 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit any such statement necessary to make the statements not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA. On January 8, 2019, FERC issued a final rule increasing the maximum civil penalty for violations of the NGA from $1,238,271 per day per violation to $1,269,500 per day per violation to account for inflation pursuant to the Federal Civil Penalties Inflation Adjustment Improvement Act of 2015. The anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to the FERC's jurisdiction which includes the reporting requirements under Order 704 (as defined and described below). Therefore, EPAct 2005 was a significant expansion of the FERC's enforcement authority. Range has not been affected differently than any other producer of natural gas by this act. Failure to comply with applicable laws and regulations with respect to EPAct 2005 could result in substantial penalties and the regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations with respect to EPAct 2005, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the FERC, other federal regulatory entities and the courts. We cannot predict when or whether any such proposals may become effective.

In December 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are required to report to the FERC, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the FERC on May 1 of each year, to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with the FERC's policy statement on price reporting.

Intrastate gas pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate gas pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates, varies from state to state. Additional proposals and proceedings that might affect the gas industry are considered from time to time by the U.S. Congress, FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their impact, if any, on our operations. We believe that the regulation of intrastate gas pipeline transportation rates will not affect our operations in any way that is materially different from its effects on similarly situated competitors.

Natural gas processing. We depend on gas processing operations owned and operated by third parties. There can be no assurance that these processing operations will continue to be unregulated in the future. However, although the processing facilities may not be directly related, other laws and regulations may affect the availability of gas for processing, such as state regulation of production rates and maximum daily production allowable from gas wells, which could impact our processing.

Gas gathering. Section 1(b) of the NGA exempts gas gathering facilities from FERC jurisdiction. We believe that our gathering facilities meet the tests FERC has traditionally used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. Thus, we cannot guarantee that the jurisdictional status of our gas gathering facilities will remain unchanged.

While we own or operate some gas gathering facilities, we also depend on gathering facilities owned and operated by third parties to gather from our properties, and therefore we are affected by the rates charged by these third parties for gathering services. To the extent that changes in federal or state regulations affect the rates charged for gathering services at any of these third-party facilities, we may also be affected by these changes. We do not anticipate that we would be affected differently than similarly situated gas producers.

Regulation of transportation and sale of oil and NGLs. Intrastate liquids pipeline transportation rates, terms and conditions are subject to regulation by numerous federal, state and local authorities and, in a number of instances, the ability to transport and sell such products on interstate pipelines is dependent on pipelines that are also subject to FERC jurisdiction under the Interstate Commerce Act (the "ICA"). We do not believe these regulations affect us differently than other producers.

The ICA requires that pipelines maintain a tariff on file with the FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before the FERC.

The FERC currently regulates rates of interstate liquids pipelines, primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by the FERC. For the five-year period beginning in July 2016, the FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23 percent. This adjustment is subject to review every five years. Under the FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exits between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. Increases in liquids transportation rates may result in lower revenue and cash flow.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity by current shippers or capacity requests are received from a new shipper. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Environmental and Occupational Health and Safety Matters

Our operations are subject to numerous federal, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may include but are not limited to:

- the acquisition of a permit before construction commences;
- restriction of the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines;
- governing the sourcing and disposal of water used in the drilling and completion process;
- limiting or prohibiting drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas;
- requiring some form of remedial action to prevent or mitigate pollution from existing and former operations such as plugging abandoned wells or closing earthen impoundments; and
- imposing substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings.

These laws and regulations also may restrict the rate of production. Moreover, changes in environmental laws and regulations often occur, and any changes that result in more stringent and costly well construction, drilling, water management or completion activities or more restrictive waste handling, storage, transport, disposal or cleanup requirements for any substances used or produced in our operations could materially adversely affect our operations and financial position, as well as those of the oil and natural gas industry in general.

Oil and gas activities have increasingly faced opposition from environmental organizations and, in certain areas, have been, restricted or banned by governmental authorities in response to concerns regarding the prevention of pollution or the protection of the environment. Moreover, some environmental laws and regulations may impose strict liability regardless of fault or knowledge, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties at sites we currently own or where we have sent wastes for disposal. To the extent future laws or regulations are implemented or other governmental action is taken that prohibits, restricts or materially increases the costs of drilling, or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected. The following is a summary of some of the environmental laws to which our operations are subject.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release or threatened release of a "hazardous substance" into the environment. These persons may include owners or operators of the disposal site or sites where the hazardous substance release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, all of these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties, pursuant to environmental statutes, common law or both, to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Although petroleum, including crude oil and natural gas, is not a "hazardous substance" under CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and that releases of such wastes may therefore give rise to liability under CERCLA. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA. In addition, certain state laws also regulate the disposal of oil and natural gas wastes. New state and federal regulatory initiatives that could have a significant adverse impact on us may periodically be proposed and enacted.

Waste handling. We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA") and comparable state laws, which impose requirements related to the handling and disposal of non-hazardous solid wastes and hazardous wastes. Drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy are currently regulated by the United States Environmental Protection Agency ("EPA") and state agencies under RCRA's less stringent non-hazardous solid waste provisions. It is possible that these solid wastes could in the future be reclassified as hazardous wastes, whether by amendment of RCRA or adoption of new laws, which could significantly increase our costs to manage and dispose of such wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous wastes. Although the costs of managing wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies in our industry. Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

We currently own or lease, and have in the past owned or leased, properties that have been used for many years for the exploration and production of crude oil and natural gas. Petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such materials have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and comparable state laws and regulations. Under such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination.

Water discharges and use. The Federal Water Pollution Control Act, as amended (the “CWA”), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. These laws also prohibit the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” in connection with on-site storage of greater than threshold quantities of oil. We regularly review our natural gas and oil properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans, the costs of which are not expected to be substantial.

The Oil Pollution Act of 1990, as amended ("OPA"), contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from an oil spill, including, but not limited to, the costs of responding to a release of oil to surface waters. While we believe we have been in substantial compliance with OPA, noncompliance could result in varying civil and criminal penalties and liabilities.

The Underground Injection Control Program authorized by the Safe Drinking Water Act prohibits any underground injection unless authorized by a permit. In connection with our operations, Range may dispose of produced water in underground wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. However, because some states have become concerned that the disposal of produced water could under certain circumstances contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal. For example, in January 2016, Ohio lawmakers proposed new legislation that would, among other things, require injection wells be located more than 2,000 feet from any occupied dwelling. While that particular legislation did not become law, Ohio lawmakers proposed new legislation in 2018 that would limit the number of injection wells in each county. Should similar onerous regulations or bans relating to underground wells be placed in effect in areas where Range has significant operations, there could be an impact on Range's ability to operate.

Hydraulic fracturing. Hydraulic fracturing, which has been used by the industry for over 60 years, is an important and common practice to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely apply hydraulic fracturing techniques as part of our operations. This process is typically regulated by state environmental agencies and oil and natural gas commissions; however, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act (as defined below) regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; proposed effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, while the Federal Bureau of Land Management ("BLM") released a final rule setting forth disclosure requirements and other regulatory mandates for hydraulic fracturing on federal lands in March 2015, on December 29, 2017, the U.S. Department of Interior rescinded the 2015 rule that would have set new environmental limitations on hydraulic fracturing, or fracking, on public lands because it believed the 2015 rule imposed administrative burdens and compliance costs that were not justified. Moreover, from time to time, Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition to any actions by Congress, certain states in which we operate, including Pennsylvania, have adopted, and other states are considering adopting, regulations imposing or that could impose new or more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing operations. States could also elect to prohibit hydraulic fracturing altogether, such as in the states of New York, Vermont and Maryland. Local governments also may seek to adopt ordinances within their jurisdiction regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we may incur additional, more significant, costs to comply with such requirements. As a result, we could also become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

In addition, certain government reviews are underway that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA issued its final report on the potential of hydraulic fracturing to impact drinking water resources through water withdrawals, spills, fracturing directly into such resources, underground migration of liquids and gases, and inadequate treatment and discharge of wastewater which did not find evidence that these mechanisms have led to widespread, systematic impacts on drinking water resources. However, the EPA’s report did identify future efforts that could be taken to further understand the potential of hydraulic fracturing to impact drinking water resources, including ground water and surface water monitoring in areas with hydraulically fractured oil and gas production wells. Based on the EPA’s study, existing regulations and our practices, we do not believe our hydraulic fracturing operations are likely to impact drinking water resources, but the EPA study could result in initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

We believe that our hydraulic fracturing activities follow applicable industry practices and legal requirements for groundwater protection and that our hydraulic fracturing operations have not resulted in material environmental liabilities. We do not maintain insurance policies intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our existing insurance policies would cover any alleged third-party bodily injury and property damage caused by hydraulic fracturing including sudden and accidental pollution coverage.

Air emissions. The Clean Air Act of 1963 (as amended, the “Clean Air Act”), and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions. We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals for emissions of pollutants. For example, pursuant to then President Obama's Strategy to Reduce Methane Emissions in August 2015, the EPA proposed new regulations that would set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Obama Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. The EPA finalized these new regulations on June 3, 2016 to be effective August 2, 2016; however, on June 12, 2017 the EPA announced a proposed two year stay on these fugitive emissions standards "while the agency reconsiders them." On September 11, 2018, the EPA proposed targeted improvements to the 2016 regulations that, according to the EPA, would significantly decrease burdens on domestic energy producers. Public comments on the proposed regulations were due by December 17, 2018, but no public hearing has been scheduled. Therefore, the date when and if these standards may become implemented and exactly what they will require is still not known. In another example, in October 2015, the EPA enacted a final rule that revised the National Ambient Air Quality Standard for ozone to 70 parts per billion for both the 8-hour primary and secondary standards. Also, in June 2018, the Pennsylvania Department of Environmental Protection ("PDEP") adopted heightened permitting conditions for all newly permitted or modified natural gas compressor stations, processing plants and transmission stations constructed, modified, or operated in Pennsylvania in an effort to regulate emissions of the GHG methane at such sites. In furtherance of the PDEP's mission to regulate methane emissions, in December 2018, the PDEP proposed a plan to regulate emissions of volatile organic compounds (including methane) at existing well sites and compressor stations, which, among other obligations, would require natural gas operators to perform quarterly leak detection and remediation. Compliance with these or any similar subsequently enacted regulatory initiatives could directly impact us by requiring installation of new emission controls on some of our equipment, resulting in longer permitting timelines, and significantly increasing our capital expenditures and operating costs, which could adversely impact our business.

Climate change. In 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present a danger to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic conditions. Based on these findings, the EPA adopted regulations under the existing Clean Air Act establishing Title V and Prevention of Significant Deterioration ("PSD") permitting reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. We could become subject to these Title V and PSD permitting reviews and be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if such facilities emitted volumes of GHGs in excess of threshold permitting levels. The EPA has also adopted rules requiring the reporting of GHG emissions from specified emission sources in the United States on an annual basis, including certain oil and natural gas production facilities, which include several of our facilities. We believe that our monitoring activities and reporting are in substantial compliance with applicable obligations.

Congress has from time to time considered legislation to reduce emissions of GHGs and there have been a number of federal regulatory initiatives to address GHG emissions in recent years, such as the establishing of Title V and PSD permitting reviews for GHG emissions, as described in more detail above. Additionally, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future federal or state laws and regulations, or international compacts could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements. On an international level, the United States was one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets, which agreement formally entered into force on November 4, 2016. While the United States formally accepted that agreement in September 2016, on June 1, 2017, President Trump determined to withdraw the United States from the Paris Agreement. Under the terms of the Paris Agreement, the earliest possible effective date for withdrawal by the United States is November 4, 2020, four years after the agreement came into effect. The United States' adherence to the exit process is uncertain and the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time and, as a result of this uncertainty, it is not possible to determine how the Paris Agreement or any separately negotiated agreement could impact us.

While it is unclear at this time whether President Trump or Congress will pursue legislation or regulation to address GHG emissions in light of the planned withdrawal of the Paris Agreement, any such legislation or regulatory programs could also increase the cost of consuming, and thereby could reduce demand for the oil and natural gas that we produce. However, President Trump has taken certain actions since taking office that have begun to establish a national policy in favor of energy independence and economic growth. For example, on March 28, 2017, President Trump issued an Executive Order for the purpose of facilitating the development of United States energy resources and reducing unnecessary regulatory burdens associated with the development of those resources. Through the Executive Order, President Trump has directed agencies to review existing regulations that potentially burden the development of domestic energy resources, and appropriately suspend, revise, or rescind regulations that unduly burden the development of United States energy resources beyond what is necessary to protect the public interest or otherwise comply with the law. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Activities on federal lands. Oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act, as amended ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Currently, we have minimal exploration and production activities on federal lands. However, for those current activities as well as for future or proposed exploration and development plans on federal lands, we will be required to obtain governmental permits or authorizations that are subject to the requirements of NEPA. This process has the potential to delay or limit, or increase the cost of, the development of oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

Endangered species. The federal Endangered Species Act of 1973, as amended (the "ESA"), restricts activities that may affect endangered and threatened species or their habitats. If endangered species are located in an area where we wish to conduct seismic surveys, development activities or abandonment operations, or are located in an area where new pipelines are planned, the work could be prohibited or delayed or expensive mitigation may be required. Moreover, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas. As a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service ("FWS") was required to make a determination on the listing of numerous species as endangered or threatened under the Endangered Species Act prior to the completion of the agency's 2017 fiscal year. For example, while the lesser prairie chicken is not currently designated as threatened or endangered, in November 2016, the FWS issued its 90-day findings in response to a petition to reclassify the lesser prairie chicken under the ESA. In those findings, FWS found that the petition presented substantial information that the petitioned action may be warranted, prompting a thorough status review. We cannot predict the outcome of this review process. The designation of currently unprotected species, including the lesser prairie chicken, as threatened or endangered in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

The Migratory Bird Treaty Act ("MBTA") implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. In accordance with this law, the taking, killing or possessing of migratory birds covered under this act is unlawful without a permit. If there is the potential to adversely affect migratory birds as a result of our operations, we may be required to obtain necessary permits to conduct those operations, which may result in specified operating restrictions on a temporary, seasonal, or permanent basis in affected areas and an adverse impact on our ability to develop and produce our reserves. However, in December 2017, the U.S. Department of Interior stated in a solicitor's opinion that it will no longer prosecute oil and gas, wind and solar operators that accidentally kill birds based on a reinterpretation of the MBTA that it does not prohibit accidental takings of migratory birds.

We believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2018, nor do we anticipate that such expenditures will be material in 2019. However, we regularly incur expenditures to comply with environmental laws and we anticipate those costs will continue to be incurred in the future.

Occupational health and safety. We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended (“OSHA”), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA’s hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

GLOSSARY OF CERTAIN DEFINED TERMS

The terms defined in this glossary are used in this report.

bbl. One stock tank barrel, or 42 U.S. gallons liquid volumes, used herein in reference to crude oil or other liquid hydrocarbons.

bcf. One billion cubic feet of gas.

bcfe. One billion cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGLs, which reflects relative energy content.

btu. One British thermal unit, an energy equivalence measure. A British thermal unit is the heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing oil or natural gas in sufficient economic quantities.

Exploratory well. A well drilled to find oil or gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of oil and gas in another reservoir or to extend a known reservoir.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Henry Hub price. A natural gas benchmark price quoted at settlement date average.

mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

mcf. One thousand cubic feet of gas.

mcf per day. One thousand cubic feet of gas per day.

mcfe. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGLs, which reflects relative energy content.

mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

mmbtu. One million British thermal units.

mmcf. One million cubic feet of gas.

mmcfe. One million cubic feet of gas equivalents.

NGLs. Natural gas liquids, which are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline that can be collectively removed from produced natural gas, separated into these substances and sold.

Net acres or Net wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Present Value (PV). The present value of future net cash flows, using a 10% discount rate, from estimated proved reserves, using constant prices and costs in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions). The after tax present value is the Standardized Measure.

Productive well. A well that is producing oil or gas or that is capable of production.

Proved developed non-producing reserves. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed reserves. Proved reserves 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 extracting equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Proved reserves. The quantities of crude oil, natural gas and NGLs that geological and engineering data can estimate with reasonable certainty to be economically producible within a reasonable time from known reservoirs under existing economic, operating and regulatory conditions prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

Proved undeveloped reserves. Proved reserves 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.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

Reserve life index. Proved reserves at a point in time divided by the then production rate (annually or quarterly).

Royalty acreage. Acreage represented by a fee mineral or royalty interest which entitles the owner to receive free and clear of all production costs a specified portion of the oil and gas produced or a specified portion of the value of such production.

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

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission’s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

tcfe. One trillion cubic feet of natural gas equivalents, with one barrel of NGLs or crude oil being equivalent to 6,000 cubic feet of natural gas.

Unproved properties. Properties with no proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens, and to all costs of exploration, development and operations, and all risks in connection therewith.

Unconventional play. A term used in the oil and gas industry to refer to a play in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds or (3) shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation or other special recovery processes in order to achieve economic flow rates.

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ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. The following summarizes the known material risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in foregoing pages under "Disclosures Regarding Forward-Looking Statements" and other information included and incorporated by reference into this Annual Report on Form 10-K. These risks are not the only risks we face. Our business could also be impacted by additional risks and uncertainties not currently known to us or that we currently deem to be immaterial.

Risks Related to Our Business

Volatility of natural gas, NGLs and oil prices significantly affects our cash flow and capital resources and could hamper our ability to operate economically. Natural gas, NGLs and oil prices are volatile, and a decline in prices adversely affects our profitability and financial condition. The oil and gas industry is typically cyclical and we expect the volatility to continue. Between 2015 and 2018, the average NYMEX monthly settlement price of natural gas has been as high as $4.72 per Mmbtu and as low as $1.71 per Mmbtu. During that same time frame, the average NYMEX monthly oil settlement price was as high as $70.76 per barrel and as low as $30.62 per barrel. Over the past few months, natural gas and oil prices have continued their volatility with the average NYMEX monthly settlement price for natural gas for February 2019 decreasing to $2.95 per Mmbtu and the monthly settlement for crude oil increasing to $51.55 per barrel in January 2019. Until recently, NGLs have suffered significant recent declines in realized prices. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, which adds further volatility to the pricing of NGLs. A further or extended decline in commodity prices could materially and adversely affect our business, cash flow, financial condition and results of operations. Natural gas prices are likely to affect us more than oil prices because approximately 67% of our December 31, 2018 proved reserves are natural gas.

Natural gas, NGLs and oil prices fluctuate in response to changes in supply and demand, market uncertainty and other factors that are beyond our control. Long-term supply and demand for natural gas, NGLs and oil is uncertain and subject to a myriad of factors such as:

- the domestic and foreign supply of, and demand for, natural gas, NGLs and oil;
- domestic and world-wide economic conditions;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;
- weather conditions;
- technological advances affecting energy consumption and production;
- the price and level of foreign imports;
- U.S. domestic and worldwide economic conditions;
- the availability, proximity and capacity of transportation facilities, processing and storage and refining facilities;
- the price and availability of, and demand for, alternative fuels;
- the effect of worldwide energy conservation efforts;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations that work together to agree and maintain oil price and production controls;
- expansion of U.S. exports of oil, NGLs and/or liquefied natural gas;
- military, economic and political conditions in natural gas and oil producing regions;
- the cost of exploring for, developing, producing, transporting and marketing natural gas, NGLs and oil; and
- domestic (federal, state and local) and foreign governmental regulations and taxation, including environmental regulations.

Lower natural gas, NGLs and oil prices may not only decrease our revenues and cash flow on a per unit basis but also may reduce the amount of natural gas, NGLs and oil that we can economically produce. A reduction in production could result in a shortfall in expected cash flows and require a reduction in capital spending or require additional borrowing. Without the ability to fund capital expenditures, we would be unable to replace reserves which would negatively affect our future rate of growth. Lower natural gas, NGLs and oil prices may also result in a reduction in the borrowing base under our bank credit facility, taking into account the value of our estimated proved reserves, which is adversely affected by declines in natural gas, NGLs and oil prices. The borrowing base under our bank credit facility, which is determined by our lenders at their discretion, is subject to redetermination annually by each May and for event driven unscheduled redeterminations.

Producing natural gas, NGLs and oil may involve unprofitable efforts. As of December 31, 2018, the relationship between the price of oil and the price of natural gas continues to be at a wide spread. NGLs production is a by-product of natural gas production. At times, we and other producers may choose to sell natural gas at below cost, or otherwise dispose of natural gas to allow for the profitable sale of only oil, NGLs and condensate. The prices of NGLs can be unpredictable. For example, over the past four years, the average Mont Belvieu NGL composite price has been as high as $0.87 per gallon and as low as $0.30 per gallon. Such volatility in the pricing of NGLs complicates such decisions and may materially and adversely affect the profitability of such decisions.

Information concerning our reserves and future net cash flow estimates is uncertain. There are numerous uncertainties inherent in estimating quantities of proved natural gas and oil reserves and their values, including many factors beyond our control. Estimates of proved reserves are by their nature uncertain and depend on many assumptions relating to current and further economic conditions and commodity prices. To the extent we experience a sustained period of reduced commodity prices, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Although we believe these estimates are reasonable, actual production, revenues and costs to develop will likely vary from estimates and these variances could be material.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of natural gas and oil that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may calculate different estimates of reserves and future net cash flows based on the same available data. Because of the subjective nature of natural gas, NGLs and oil reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of natural gas, NGLs and oil production;
- the revenues and costs associated with that production;
- the amount and timing of future development expenditures; and
- future commodity prices.

The discounted future net cash flows from our proved reserves included in this report should not be considered as the market value of the reserves attributable to our properties. As required by United States generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based on a twelve month average price (first day of the month) while cost estimates are based on current year-end economic conditions. Actual future prices and costs may be materially higher or lower. In addition, the ten percent discount factor that is required to be used to calculate discounted future net cash flows for reporting purposes under United States generally accepted accounting principles is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and gas industry in general.

If natural gas, NGLs and oil prices remain depressed or drilling efforts are unsuccessful, we may be required to record write downs of our proved natural gas and oil properties. We have been required to write down the carrying value of certain of our natural gas and oil properties in the past and there is a risk that we will be required to take additional writedowns in the future. For example, in first quarter 2016, we recorded a $43.0 million proved property impairment in Western Oklahoma. In third quarter 2017, we recorded a $63.7 million proved property impairment related to our natural gas and oil properties in the Texas Panhandle and Northern Oklahoma. In first quarter 2018, we recorded a $7.3 million proved property impairment in Northern Oklahoma. These impairments were due to the potential sale of certain of these properties. Writedowns may occur in the future when natural gas and oil prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in our drilling results or mechanical problems with wells where the cost to redrill or repair is not supported by the expected economics. Because our reserves are predominately natural gas, changes in natural gas prices have a more significant impact on our financial results.

Accounting rules require that the carrying value of natural gas and oil properties be periodically reviewed for possible impairment. Impairment is recognized for the excess of book value over fair value when the book value of a proven property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on natural gas and oil prices at the time of the impairment review, or as a result of continuing evaluation of drilling results, production data, economics, divestiture activity, and other factors. A write down constitutes a non-cash charge to earnings and does not impact cash or cash flows from operating activities; however, it reflects our long-term ability to recover an investment, reduces our reported earnings and increases certain leverage ratios.

We evaluate our unproved oil and gas properties for impairment and could be required to recognize noncash charges in the earnings of future periods. At December 31, 2018, our unproved natural gas and oil properties carrying value was $2.1 billion. Our analysis of these costs is affected by the results of exploration activities, commodity price outlooks, potential shifts in business strategy employed by management, planned future sales or expiration of all or a portion of the leases. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. We have been required to write down the carrying value of our unproved property in the past and there is a risk that we will be required to take additional write downs in the future. We have recorded abandonment and impairment expense related to unproved properties of $515.0 million in 2018 compared to $269.7 million in 2017 and $30.1 million in 2016.

Significant capital expenditures are required to replace our reserves. Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, our bank credit facility and debt and equity issuances. We have also engaged in asset monetization transactions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of natural gas, NGLs and oil and our success in developing and producing new reserves. If our access to capital were limited due to various factors, which could include a decrease in revenues due to lower natural gas, NGLs and oil prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to replace our reserves. We may not be able to incur additional bank debt, issue debt or equity, engage in asset monetization or access other methods of financing on an economic basis to meet our reserve replacement requirements.

The amount available for borrowing under our bank credit facility is subject to a borrowing base, which is determined by our lenders, at their discretion, taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. Declines in natural gas, NGLs and oil prices adversely impact the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base and could result in a determination to lower our borrowing base. A further or extended decline in commodity prices could materially and adversely affect our business, financial condition and results of operations.

Our future success depends on our ability to replace reserves that we produce. Because the rate of production from natural gas and oil properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional natural gas, NGLs and oil reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future natural gas, NGLs and oil production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot be certain that we will be able to find or acquire and develop additional reserves at an acceptable cost.

We acquire significant amounts of unproved property to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire both producing and unproved properties as well as lease undeveloped acreage that we believe will enhance growth potential and increase our earnings over time. However, we cannot be certain that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells. Low commodity prices may cause us to delay our drilling plans and as a result, we may lose our right to develop the related property.

Drilling is an uncertain and costly activity. The cost of drilling, completing, and operating a well is often uncertain, and many factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough natural gas, NGLs and oil to be commercially viable after drilling, operating and other costs. There is no way to conclusively know in advance of drilling and testing whether any particular prospect will yield natural gas, NGLs or oil in commercially viable quantities. Furthermore, our drilling and producing operations may be curtailed, delayed, or canceled as a result of a variety of factors, including, but not limited to:

- increases in the costs, shortages or delivery delays of drilling rigs, equipment, water for hydraulic fracturing services, labor, or other services;
- unexpected operational events and drilling conditions;
- reductions in natural gas, NGLs and oil prices;
- limitations in the market for natural gas, NGLs and oil;
- adverse weather conditions and changes in weather patterns;
- facility or equipment malfunctions or operator error;
- equipment failures or accidents;
- loss of title and other title-related issues;
- pipe or cement failures and casing collapses;
- compliance with, or changes in, environmental, tax and other governmental requirements;

- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, and unauthorized discharges of toxic gases;
- lost or damaged oilfield drilling and service tools;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- pressure or irregularities in formations;
- fires;
- natural disasters;
- surface craterings and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- availability and timely issuance of required governmental permits and licenses; and
- civil unrest or protest activities.

If any of these factors were to occur, we could lose all or a part of our investment, or we could fail to realize the expected benefits, either of which could materially and adversely affect our revenue and profitability.

Our operations involve utilizing drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing horizontal wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation state.

Drilling in emerging areas is more uncertain than drilling in areas that are more developed and have a longer history of established drilling operations. New discoveries and emerging formations have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are worse than anticipated, the return on investment for a particular project may not be as attractive as anticipated and we may recognize noncash impairment charges to reduce the carrying value of unproved properties in those areas.

Our identified drilling locations are scheduled out over multiple years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our development strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory and zoning approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. These risks are greater at times and in areas where the pace of our exploration and development activity slows. As such, our actual drilling activities may materially differ from those presently identified. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our business and results of operations.

We may incur losses as a result of title defects in the properties in which we invest. It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition.

Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in the assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Our producing properties are largely concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in a significant geographic area. Our producing properties are geographically concentrated in the Appalachian Basin in Pennsylvania. At December 31, 2018, 94% of our total estimated proved reserves were attributable to properties located in Pennsylvania. As a result of this concentration, 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, litigation, state politics, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or interruption of the processing or transportation of crude oil, condensate, natural gas or NGLs.

New technologies may cause our current exploration and drilling methods to become obsolete. There have been rapid and significant advancements in technology in the natural gas and oil industry, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial increase in cost. Further, competitors may obtain patents which might prevent us from implementing new technologies. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Our indebtedness could limit our ability to successfully operate our business. We are leveraged and our exploration and development program will require substantial capital resources depending on the level of drilling and the expected cost of services. Our existing operations will also require ongoing capital expenditures. In addition, if we decide to pursue additional acquisitions, our capital expenditures may increase, both to complete such acquisitions and to explore and develop any newly acquired properties.

The degree to which we are leveraged could have other important consequences, including the following:

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- a portion of our borrowings is at variable rates of interest, making us vulnerable to increases in interest rates;
- we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;
- our degree of leverage may make us more vulnerable to a downturn in our business or the general economy;

- we are subject to numerous financial and other restrictive covenants contained in our existing debt agreements, which restrict our ability to engage in certain activities and could limit our growth, and the breach of such covenants, which could materially and adversely impact our financial performance;
- our debt level could limit our flexibility to grow the business and in planning for, or reacting to, changes in our business and the industry in which we operate; and
- we may have difficulties borrowing money in the future.

The risks described above may further increase in the event we incur additional debt. In addition to those risks above, we may not be able to obtain funding on acceptable terms.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations. We expect our earnings and cash flow to fluctuate from year to year due to the cyclical nature of our business. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or restructure our debt. Our ability to restructure our debt will depend on the condition of the capital markets and our financial condition at such time. Any restructuring of debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on, and principal of, our debt in the future and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and impair our liquidity.

We receive debt ratings from the major credit rating agencies in the United States. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term growth opportunities. Liquidity, asset quality, cost structure, product mix and commodity pricing levels are also considered by the rating agencies. A ratings downgrade could adversely impact our ability to access debt markets in the future, increase the cost of future debt and potentially require us to post letters of credit or other forms of collateral for certain obligations.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part. The terms of our senior indebtedness, including our revolving credit facility, contain cross-default provisions which provide that we will be in default under such agreements in the event of certain defaults under our indentures or other loan agreements. Accordingly, should an event of default above certain thresholds occur under any of those agreements, we face the prospect of being in default under all of our debt agreements, obliged in such instance to satisfy all of our outstanding indebtedness and unable to satisfy all of our outstanding obligations simultaneously. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us, which would negatively affect our ability to implement our business plan, make capital expenditures and finance our operations.

We are subject to financing and interest rate exposure risks. Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in our credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, at December 31, 2018, approximately 75% of our debt is at fixed interest rates with the remaining 25% subject to variable interest rates.

Disruptions or volatility in the global finance markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results. We are exposed to some credit risk related to our bank credit facility to the extent that one or more of our lenders may be unable to provide necessary funding to us under our existing revolving line of credit if it experiences liquidity problems.

A financial downturn or negative credit market conditions may have lasting effects on our liquidity, business and financial condition that we cannot predict. Liquidity is essential to our business. Our liquidity could be substantially negatively affected by an inability to obtain capital in the long-term or short-term debt markets, or equity capital markets or an inability to access bank financing. A prolonged credit crisis or turmoil in the domestic or global financial systems could materially affect our liquidity, business and financial condition. These conditions have adversely impacted financial markets and created substantial volatility and uncertainty previously and, with the related negative impact on global economic activity and the financial markets, could do so again. Negative credit market conditions could materially affect our liquidity and may inhibit our lenders from fully funding our bank credit facility or cause them to make the terms of our bank credit facility costlier and more restrictive. We are subject to annual reviews, as well as unscheduled reviews, of our borrowing base under our bank credit facility, and we do not know the results of future redeterminations or the effect of then-current oil and natural gas prices on that process. A weak economic environment could also adversely affect the collectability of our trade receivables or performance by our suppliers or other third parties that we contract with to operate our properties or provide facilities. Additionally, negative economic conditions could lead to reduced demand or lower prices for natural gas, NGLs and oil, which could have a negative impact on our revenues.

Derivative transactions may limit our potential gains and involve other risks. To manage our exposure to price risk, we currently, and may in the future, enter into derivative arrangements, utilizing commodity derivatives with respect to a portion of our future production. Such hedges are designed to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if natural gas, NGLs and oil prices rise above the price established by the hedge. In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

We cannot be certain that any derivative transaction we may enter into will adequately protect us from declines in the prices of natural gas, NGLs or oil. Furthermore, where we choose not to engage in derivative transactions in the future, we may be more adversely affected by changes in natural gas, NGLs or oil prices than our competitors who engage in derivative transactions. Lower natural gas, NGLs and oil prices may also negatively impact our ability to enter into derivative contracts at favorable prices.

We are exposed to a risk of financial loss if a counterparty fails to perform under a derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to mitigate the risk may be limited depending upon market conditions. Furthermore, the bankruptcy of one or more of our hedge providers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed to us by the distressed entity or entities. During periods of falling commodity prices, our hedge receivable positions increase, which increases our exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

Many of our current and potential competitors have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties. We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods, services and employees needed to operate and manage our business and marketing natural gas, NGLs or oil. Competitors include multinational oil companies, independent production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do. As a result, these competitors may be able to address these competitive factors more effectively than we can or withstand industry downturns more easily than we can. For more discussion regarding competition, see Items 1 & 2. Business and Properties – Competition.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition. Our future growth prospects are dependent upon our ability to identify optimal strategies for investing our capital resources to produce rates of return. In developing our business plan, we consider allocating capital and other resources to various aspects of our business including well development (primarily drilling), reserve acquisitions, exploratory activity, corporate items and other alternatives. We also consider our likely sources of capital, including cash generated from operations and borrowings under our credit facility. Notwithstanding the determinations made in the development of our business plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and future growth may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our business plan and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

The natural gas and oil industry is subject to extensive regulation. The natural gas and oil industry is subject to various types of regulations in the United States by local, state and federal agencies. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing our regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on participants in the natural gas and oil industry. Compliance with such rules and regulations often increases our cost of doing business, delays our operations and, in turn, decreases our profitability.

Our operations are subject to numerous and increasingly strict federal, state and local laws, regulations and enforcement policies relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies and may incur costs arising out of property or natural resource damage or injuries to employees and other persons. These costs may result from our current and former operations and may even be caused by previous owners of property we own or lease or relate to third-party sites where we have taken materials for recycling or disposal. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as corrective action orders. Matters subject to regulation include, but are not limited to, the following:

- the amounts and types of substances and materials that may be released into the environment;
- responding to unexpected releases to the environment;
- reports and permits concerning exploration, drilling, production and other regulated activities;
- the location and spacing of wells;
- unitization and pooling of properties;
- calculating royalties on oil and gas produced under federal and state leases; and
- taxation.

Under such laws and regulations, we could be liable for personal injuries, property damages, oil spills, discharges of hazardous materials, remediation and clean-up costs, natural resource damages and other environmental damages. We also could be required to install expensive pollution control measures or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. If we incur these costs or damages it may reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

The subject of climate change continues to receive attention from scientists, legislators, governmental agencies and the general public. There is an ongoing debate as to the extent to which our climate is changing, the potential causes of this change and its potential impacts. Some attribute global warming to increased levels of GHGs, including carbon dioxide and methane, which has led to significant legislative and regulatory efforts to limit GHG emissions.

Congress has from time to time considered legislation to reduce emissions of GHGs and there have been a number of federal regulatory initiatives to address GHG emissions in recent years. These include the establishing of Title V and PSD permitting reviews for GHG emissions from certain large stationary sources that are already major potential sources of certain principal, or criteria, pollutant emissions, and the implementation of a GHG monitoring and reporting program for certain sectors of the natural gas and oil industry, including onshore and production, which includes certain of our operations. Additionally, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs, in which major sources of GHG emissions acquire and surrender emission allowances in return for emitting those GHGs. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations to control or restrict emissions, taxes or other charges to deter emissions of GHGs, energy efficiency requirements to reduce demand, or other regulatory actions. For example, the EPA finalized new regulations in 2016 that would set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities in an effort to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025; however, on June 12, 2017 the EPA announced a proposed two year stay on fugitive emissions standards “while the agency reconsiders them.” On September 11, 2018, the EPA proposed targeted improvements to the 2016 regulations that, according to the EPA would significantly decrease burdens on domestic energy producers. The date when and if these standards may become implemented and exactly what they will require is still not known. Notwithstanding these federal standards, state regulations with respect to emissions of GHGs could continue to become more restrictive regardless of the decreased burdens under federal regulations. For example, in June 2018 the PDEP adopted heightened permitting conditions for all newly permitted or modified natural gas compressor stations, processing plants and transmission stations constructed, modified, or operated in Pennsylvania in an effort to regulate emissions of the GHG methane at such sites. Then, in December 2018, the PDEP proposed a plan to regulate emissions of volatile organic compounds (including methane) at existing wells sites and compressor stations, which, among other obligations, would require natural gas operators to perform quarterly leak detection and remediation. If these or any other actions to address GHG emissions do become implemented in the future, they could:

- result in increased costs associated with our operations;
- increase other costs to our business;
- affect the demand for natural gas; and
- impact the prices we charge our customers.

Adoption of additional federal or state requirements mandating a reduction in GHG emissions could have far-reaching and significant impacts on the energy industry and the U.S. economy. We cannot predict the potential impact of such laws or regulations, or international compacts on our future consolidated financial condition, results of operations or cash flows. For more information regarding the environmental regulation of our business, see Items 1 & 2. Business and Properties – Environment and Occupational Health and Safety Matters.

Our business is subject to operating hazards that could result in substantial losses or liabilities that may not be fully covered under our insurance policies. Natural gas, NGLs and oil operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pipe or cement failures, pipeline ruptures or spills, vandalism, pollution, releases of toxic gases, adverse weather conditions or natural disasters, and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- investigatory and cleanup responsibilities;
- regulatory investigations and penalties or lawsuits;
- suspension of operations; and
- repairs to resume operations.

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We maintain insurance against many, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses.

We currently have insurance policies covering our operations that include coverage for general liability, excess liability, physical damage to our oil and gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employer's liability and other coverages. Our insurance policies provide coverage for losses or liabilities relating to pollution, but are largely limited to coverage for sudden and accidental occurrences. For example, we maintain operator's extra expense coverage for obligations, expenses or claims that we may incur from a sudden incident that results in negative environmental effects, including obligations, expenses or claims related to seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operator's extra expense coverage would be our primary source of coverage, with the general liability and excess liability coverage referenced above also providing certain coverage.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse effect on our business, financial condition and results of operations.

Additionally, we rely to a large extent on facilities owned and operated by third parties and damage to, or destruction of, those third-party facilities could affect our ability to process, transport and sell our production. To a limited extent, we maintain business interruption insurance related to a third-party processing plant in Pennsylvania where we are insured for potential losses from the interruption of production caused by loss of or damage to the processing plant.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, we have not received a declaratory order from the FERC regarding our natural gas gathering pipelines and the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation. As a result, the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC, the courts and Congress.

While we believe our natural gas gathering operations are generally exempt from FERC regulation under the NGA, our gas gathering operations may be subject to certain FERC reporting and posting requirements in a given year. The FERC requires certain participants in the natural gas market, including certain gathering facilities and natural gas marketers that engage in a minimum level of natural gas sales or purchases, to submit annual reports to the FERC on the aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices.

Other FERC regulations may indirectly impact our operations and the markets for products derived from these operations. The FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market-center promotion, may indirectly affect the intrastate natural gas market. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot be certain that the FERC will continue this approach as it considers matters such as pipeline rates, rules and policies that may affect rights of access to transportation capacity. For more information regarding the regulation of our operations, see Items 1 & 2. Business and Properties – Governmental Regulation.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under EPAct 2005, the FERC has civil penalty authority under the NGA, which can include both monetary penalties and disgorgement of profits associated with any violation. On January 8, 2019, FERC issued a final rule increasing the maximum monetary civil penalty for violations of the NGA from $1,238,271 per day per violation to $1,269,500 per day per violation to account for inflation pursuant to the Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015. While our operations have not been regulated as a natural gas company by the FERC under the NGA, the FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to the FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by the FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC from time to time. Failure to comply with those regulations in the future could subject Range to civil penalty liability. For more information regarding the regulation of our operations, see Items 1 & 2. Business and Properties – Governmental Regulation.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated or postponed and additional federal or state taxes or fees on natural gas extraction may be imposed, as a result of future legislation. Legislation has been previously proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain U.S. federal income tax benefits currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of percentage interest depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs and; (iii) an extension of the amortization period for certain geological and geophysical expenditures. However, it is unclear, whether any such changes will be enacted and if enacted, how soon any such changes could be effective. Additionally, legislation could be enacted that imposes new fees or increases the taxes on oil and natural gas extraction, which could result in increased operating costs and/or reduced consumer demand for our products. The passage of any such legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development, or could increase costs and any such changes could have an adverse affect on our financial condition, results of operations and cash flows. As of December 31, 2018, we had a tax basis of $1.7 billion related to prior years' capitalized intangible drilling costs, which will be amortized over the next five years.

The legislation commonly referred to as the Tax Cuts and Jobs Act of 2017 (the "2017 Tax Act") was signed into law on December 22, 2017 by President Trump. The 2017 Tax Act provided significant changes to the United States corporate income tax system. The changes that are effective beginning in 2018 include a federal corporate rate reduction from 35% to 21%, the elimination or reduction of certain domestic deductions and credits and limitations on the deductibility of interest expense and executive compensation, and the transition of United States international taxation from a worldwide tax system to a territorial tax system. The new law also limits the utilization of net operating loss carryforwards for losses arising in tax years beginning after 2017 to 80% of taxable income. Our net deferred tax assets and liabilities were revalued at the newly enacted U.S. corporate rate and the impact was recognized in tax expense in 2017.

In February 2012, the state legislature of Pennsylvania passed legislation creating a natural gas impact fee applicable to production in Pennsylvania. As noted above, the majority of our acreage in the Marcellus Shale is located in Pennsylvania. The legislation imposes an annual fee on natural gas and oil operators for each well drilled for a period of fifteen years. Much like a severance tax, the fee is on a sliding scale set by the Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average NYMEX natural gas prices on the last day of each month. The impact fee increases the financial burden on our operations in the Marcellus Shale. There can be no assurance that the impact fee will remain as currently structured or that additional taxes will not be imposed. There are currently proposals by the Pennsylvania Governor and various Pennsylvania state lawmakers to enact a severance tax in substitution for, or as an addition to, the impact fee already in place, which could be based on the volume of gas produced rather than on a per-well basis. In addition, a recent court case in Pennsylvania addressed the constitutionality of the 2007 net operating loss deduction ("NOLD") limitation under the Uniformity Clause of the Pennsylvania Constitution, which limited the use of NOLDs to the greater of $3 million or 12.5 percent of taxable income. On October 18, 2017, the Supreme Court of Pennsylvania issued its decision on this case holding that the NOLD limitation as applied to the 2007 taxable year at issue violated the Uniformity Clause of the Pennsylvania Constitution and struck the $3 million flat cap limitation, but not the percentage of taxable income limitation. Shortly after the Supreme Court Case, the Pennsylvania Governor signed a bill that removed the flat cap NOLD limitation and increased the percentage of taxable income limitation. For 2018, the net operating loss carryforward is limited to 35 percent of taxable income and limited to 40 percent for each year thereafter.

Changes in laws or regulations relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays and adversely affect our production. The use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs, especially shale formations such as the Marcellus Shale. The process is typically regulated by state environmental agencies and oil and gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; proposed effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, in 2015 the BLM enacted a new rule setting forth disclosure requirements and other regulatory mandates for hydraulic fracturing on federal lands; however, on December 29, 2017, the U.S. Department of Interior rescinded the 2015 rule because it believed the 2015 rule imposed administrative burdens and compliance costs that were not justified.

From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Certain states in which we operate, including Pennsylvania, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure or well-construction requirements on hydraulic fracturing operations. States could elect to prohibit hydraulic fracturing altogether, such as the states of New York, Vermont and Maryland have already done. Local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular. In the event federal, state or local restrictions or prohibitions are adopted in areas where we conduct operations, we may incur significant costs to comply with such requirements or we may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Moreover, a number of federal entities are analyzing a variety of environmental issues associated with hydraulic fracturing. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local-or regional-scale factors are more likely than others to result in more frequent or more severe impacts: 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. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, we do not believe that this multi-year study and subsequent report provides any basis for further regulation of hydraulic fracturing at the federal level. However, the EPA's report did identify future efforts that could be taken to further understand the potential of hydraulic fracturing impact to drinking water resources, including groundwater and surface water monitoring in areas with hydraulically fractured oil and gas production wells.

We use a significant amount of water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. In recent history, public concern surrounding increased seismicity has heightened focus on our industry's use of water in operations. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, and all of which could have an adverse effect on our operations and financial condition.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business. State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states, including in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. For example, in March 2018, Ohio lawmakers proposed pending legislation to limit the number of injection wells in each county to twenty-three.

We dispose of large volumes of produced water gathered from our drilling and production operations in our Louisiana fields by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitory and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of water gathered from our drilling and production activities by our own disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

The enactment 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 Wall Street Reform and Consumer Protection Act (the “Act”), enacted in July 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, including Range, that participate in that market. The Act requires the Commodities Futures Trading Commission (the “CFTC”) and the SEC to promulgate rules and regulations implementing the Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place 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. In December 2016, the CFTC voted unanimously to repropose regulations implementing limits on speculative futures and swaps positions as called for in the Act. In a separate vote, CFTC approved final aggregation regulations, which are a key component of the CFTC's existing position limits regime. In response to comments on a prior proposal published in December 2013, and on a supplemental proposal published in June 2016, the CFTC is, among other things, reproposing limits on speculative positions in twenty-five core physical commodity futures contracts and their "economically equivalent" futures, options, and swaps (referenced contracts), and is deferring action on three cash-settled commodities. The CFTC is also reproposing the definition of bona fide hedging position, as well as exemptions for bona fide hedging positions in physical commodities. Exemptions are being reproposed for, among other things, positions that are established in good faith prior to the effective date of the initial limits that would be established by regulations. As these CFTC reproposals are not yet final, the impact on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules will also require us, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements in connection with covered derivative activities. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, the Act requires that regulators establish margin rules for uncleared swaps. Rules that require end-users to post initial or variation margin could impact our liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows.

The full impact of the Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Act and new regulations could significantly increase the cost of derivative contracts or materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter or reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Act and regulations implementing the Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

Finally, the Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Act and regulations implemented thereunder is to lower commodity prices.

Laws and regulations pertaining to threatened and endangered species could delay or restrict our operations and cause us to incur substantial costs. Various federal and state statutes prohibit certain actions that adversely affect endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. These statutes include, without limitation, the ESA, the MBTA, the CWA and CERCLA. The FWS may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or oil and gas development. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the FWS was required to consider listing numerous species as endangered or threatened under the ESA before completion of the agency's 2017 fiscal year. While none of the species that the FWS listed as threatened or endangered materially affect our operations, the future designation of previously unprotected species as threatened or endangered in areas where we conduct operations could cause us to incur increased costs arising from species protection measures or could result in limitations on its exploration and production activities that could have an adverse effect on our ability to develop and produce reserves.

Our business depends on natural gas and oil transportation and NGLs processing facilities, most of which are owned by others and depends on our ability to contract with those parties. Our ability to sell our natural gas, NGLs and oil production depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties and our ability to contract with those third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships, including the financial condition of these third parties, could materially affect our operations. In some cases, we do not purchase firm transportation on third-party facilities and therefore, our production transportation can be interrupted by those having firm arrangements. In other cases, we have entered into firm transportation arrangements, particularly in the Marcellus Shale where we are obligated to pay fees on minimum volumes regardless of actual volume throughput. If production decreases due to developmental activities, taking into consideration the current commodity price environment, production related difficulties or otherwise, we may be unable to meet our obligations under existing firm transportation contracts, resulting in fees which may be significant and may have a material adverse effect on our operations. We have also entered into long-term agreements with third parties to provide natural gas gathering and processing services in the Marcellus Shale. In some cases, the capacity of gathering systems and transportation pipelines may be insufficient to accommodate potential production from existing and new wells. Federal and state regulation of natural gas and oil production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport natural gas, NGLs and oil. If any of these third-party pipelines or other facilities become partially or fully unavailable to transport or process our product, or if the natural gas quality specifications for a natural gas pipeline or facility changes so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues could be adversely affected.

The disruption of third-party facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. In particular, the disruption of certain third-party natural gas processing facilities in the Marcellus Shale could materially affect our ability to market and deliver natural gas production in that area. We have no control over when or if such facilities are restored and generally have no control over what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

In North Louisiana, we have contracts with midstream providers for gathering and processing services with minimum volume delivery commitments. We are obligated to pay fees on minimum volumes to midstream service providers regardless of actual volume throughput. These fees could be significant and may have a material adverse effect on our operations.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business. We could be subject to significant liabilities related to our acquisitions. It is generally not feasible to review in detail every individual property included in an acquisition. Ordinarily, a review is focused on higher-valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems in all of the properties, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Initial estimates of reserves may be subject to revisions following an acquisition which may materially and adversely affect the desired benefits of the acquisition.

In addition, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our acquisition strategy is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue an acquisition strategy may be hindered if we are unable to obtain financing on terms acceptable to us or regulatory approvals.

Acquisitions often pose integration risks and difficulties. In connection with prior and future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Future acquisitions could result in our incurring additional debt, contingent liabilities, expenses and diversion of resources, all of which could have a material adverse effect on our financial condition and operating results.

Significant acquisitions present potential risks, including:

- difficulties in operating a larger combined organization and integrating additional operations into ours;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographical area;
- the loss of customers or key employees from the acquired businesses;
- the diversion of management's attention from other existing business concerns;
- the failure to realize expected synergies and cost savings;
- difficulties in coordinating geographically disparate organizations, systems and facilities;
- difficulties in integrating personnel from diverse business backgrounds and organizational cultures; and
- difficulties in consolidating corporate and administrative functions.

The combined company may not be able to utilize a portion of Memorial's or Range's net operating loss carryforwards to offset future taxable income for U.S. federal tax purposes, which could adversely affect the combined company's net income and cash flows. As noted in the financial statements included with this Form 10-K, we have substantial net operating losses ("NOLs"). Utilization of these NOLs depends on many factors, including the company's future taxable income, which cannot be predicted with any accuracy. In addition, Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"), generally imposes an annual limitation on the amount of an NOL that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period, taking into account for this purpose only those stockholders (or groups of stockholders) who are deemed to own at least 5% of the corporation's stock. In the event that an ownership change has occurred—or were to occur—with respect to a corporation following its recognition of an NOL, utilization of this NOL would be subject to an annual limitation under Section 382, generally determined by multiplying the value of the corporation's stock at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382. However, this annual limitation would be increased under certain circumstances by recognized built-in gains of the corporation existing at the time of the ownership change. Any unused annual limitation with respect to an NOL generally may be carried over to later years, subject to the expiration of the NOL twenty years after it arose.

If Range is determined to have undergone an ownership change in the future, we may be unable to fully utilize our NOLs prior to their expiration. To the extent we are not able to offset future taxable income with our NOLs, operating results and cash flows may be adversely affected.

We may be unable to dispose of nonstrategic assets on attractive terms, and may be required to retain liabilities for certain matters. We regularly review our property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect our ability to dispose of nonstrategic assets or complete announced dispositions, including the availability of purchasers willing to purchase the nonstrategic assets at prices acceptable to us. Sellers typically retain 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, third parties are often unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel. Our success is highly dependent on our management personnel and none of them is currently subject to an employment contract. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

We are involved in legal proceedings that could result in substantial liabilities and materially and adversely impact our financial condition. Like many oil and gas companies, we are involved in various legal proceedings, including threatened claims, such as title, royalty, and contractual disputes. The cost to settle legal proceedings (asserted or unasserted) or satisfy any resulting judgment against us in such proceedings could result in a substantial liability or the loss of interests, which could materially and adversely impact our cash flows, operating results and financial condition. Judgments and estimates to determine accruals or range of losses related to legal proceedings could change from one period to the next, and such changes could be material. Current accruals may be insufficient to satisfy any such judgments. Legal proceedings could also result in negative publicity about Range. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions. As a natural gas and oil producer, we face various security threats, including:

- cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable;
- threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; or
- threats from terrorist acts.

Computers and telecommunication systems are used to conduct our exploration, development and production activities and have become an integral part of our business. We use these systems to analyze and store financial and operating data and to communicate internally and with outside business partners. Cyber-attacks could compromise our computer and telecommunications systems and result in disruptions to our business operations or the loss of our data and proprietary information. In addition, computers control oil and gas production, processing equipment, and distribution systems globally and are necessary to deliver our production to market. A cyber-attack against these operating systems, or the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets, and make it difficult or impossible to accurately account for production and settle transactions.

Security threats have subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our personnel, information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to harm to our employees or losses of sensitive information, losses of critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, and results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, phishing, ransomware, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could damage our reputation and lead to financial losses from unauthorized disbursement of funds and/or remedial actions, loss of business or potential liability. While we have not suffered any material losses relating to such attacks, there can be no assurance that we will not suffer such losses in the future.

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.

We may face various risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities. Opposition toward oil and gas drilling and development activity has been growing globally. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental compliance and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain projects such as the development of oil and gas shale plays. For example, environmental activists continue to advocate for increased regulations or bans on shale drilling and hydraulic fracturing in the United States, even in jurisdictions that are among the most stringent in their regulation of the industry. Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms and reduction in lease size;
- restrictions on installation or operation of production, gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing, or the disposal of related waste materials, such as hydraulic fracturing fluids and produced water;
- increased severance and/or other taxes;
- cyber-attacks;
- legal challenges or lawsuits;
- negative publicity about our business or the oil and gas industry in general;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

We may need to incur significant costs associated with responding to these initiatives. Complying with any resulting additional legal or regulatory requirements that are substantial could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Conservation measures and technological advances could reduce demand for oil and natural gas. Fuel conservation measures, alternative fuel requirements, governmental requirements for renewable energy resources, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned. Historically, our capital and operating costs have risen during periods of increasing oil, NGLs and gas prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Increased levels of drilling activity in the natural gas and oil industry could lead to increased costs of some drilling equipment, materials and supplies. Such costs may rise faster than increases in our revenue, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget.

Higher natural gas, NGLs and oil prices generally stimulate demand for ancillary services. Similarly, lower natural gas, NGLs and oil prices generally result in a decline in service costs due to reduced demand for drilling and completion services. If the current market changes and commodity prices continue to recover, we may face shortages of field personnel, drilling rigs or other equipment and supplies which could delay or adversely affect our operations.

Our financial statements are complex. Due to United States generally accepted accounting principles and the nature of our business, our financial statements continue to be complex, particularly with reference to derivatives, asset retirement obligations, equity awards, deferred taxes, long-lived assets and the accounting for our deferred compensation plans. We expect such complexity to continue and possibly increase.

Risks Related to Our Common Stock

Common stockholders will be diluted if additional shares are issued. Our ability to repurchase securities for cash is limited by our bank credit facility. We also issue restricted stock 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 subordinated notes or other securities or debt convertible into common stock to extend maturities or fund capital expenditures, including acquisitions.

Dividend limitations. Limits on the payment of dividends and other restricted payments, as defined, are imposed under our bank credit facility. These limitations may, in certain circumstances, limit or prevent the payment of dividends.

Our stock price may be volatile and you may not be able to resell shares of our common stock at or above the price you paid. The price of our common stock fluctuates significantly, which may result in losses for investors. The market price of our common stock has been volatile. From January 1, 2016 to December 31, 2018, the price of our common stock reported by the New York Stock Exchange ranged from a low of $9.23 per share to a high of $46.96 per share. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in natural gas, NGLs and oil prices;
- variations in quarterly drilling, recompletions, acquisitions and operating results;
- changes in governmental regulation and/or taxation;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel; or
- future sales of our stock and changes in our capital structure.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future and our stock price could decline as a result.

Our certificate of incorporation, bylaws, some of our arrangements with employees and Delaware law contain provisions that could discourage an acquisition or change of control of us. Our certificate of incorporation and bylaws contain provisions that may make it more difficult to effect a change of control, to acquire us or to replace incumbent management, including, for example, limitations on shareholders' ability to remove directors, call special meetings and to propose and nominate directors or otherwise propose actions for approval at stockholder meetings, as well as the ability of our board of directors to amend our certificate of incorporation and bylaws and to issue and set the terms of preferred stock without the approval of our stockholders. In addition, our change of control severance plan, change of control severance agreements with certain officers and our omnibus stock plans and deferred compensation plans contain provisions that provide for severance payments and accelerated vesting of benefits, including accelerated vesting of equity awards and acceleration of deferred compensation, upon a change of control. Section 203 of the Delaware General Corporation Law also imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions could discourage or prevent a change of control, even if it may be beneficial to our stockholders, or could reduce the price our stockholders receive in an acquisition of us.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are the subject of, or party to, a number of pending or threatened legal actions and claims arising in the ordinary course of our business. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations. We will continue to evaluate our litigation quarterly and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then-current status of litigation.

Environmental Proceedings

Our subsidiary, Range Resources – Appalachia, LLC, was notified by the Pennsylvania Department of Environmental Protection ("DEP") that it intends to assess a civil penalty under the Clean Streams Law and the 2012 Oil and Gas Act in connection with one well in Lycoming County. The DEP has directed us to prevent methane and other substances from escaping from this gas well into groundwater and a stream. We have considerable evidence that this well is not leaking and pre-drill testing of surrounding water wells showed the presence of methane in the water before commencement of our operations. While we intend to vigorously assert this position with the DEP, resolution of this matter may nonetheless result in monetary sanctions of more than $100,000.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market for Common Stock

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "RRC". During 2018, trading volume averaged approximately 7.7 million shares per day.

Holders of Record

Pursuant to the records of our transfer agent, as of February 20, 2019, there were approximately 974 holders of record of our common stock.

Dividends

The payment of dividends is subject to declaration by the board of directors and depends on earnings, capital expenditures and various other factors. The board of directors declared quarterly dividends of $0.02 per common share for each of the four quarters of 2016, 2017 and 2018. The bank credit facility allows for the payment of common and preferred dividends, with certain limitations. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of our board of directors and will depend upon among other things, our earnings, financial condition, capital requirements, levels of indebtedness and other considerations our board of directors deems relevant. For more information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Equity Compensation Plan Information

The information required by this item is incorporated herein by reference to the 2019 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2018.

Stockholder Return Performance Presentation*

The following graph is included in accordance with the SEC's executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of Range's common stock, the ISE Revere Natural Gas Index, the Dow Jones U.S. Exploration and Production Index, the S&P 500 Index and the S&P 400 Mid Cap Index for the five years ended December 31, 2018. The graph assumes that $100 was invested in the Company's common stock and each index on December 31, 2013 and that dividends were reinvested.

	2013	2014	2015	2016	2017	2018
Range Resources Corporation	$100	$64	$29	$41	$21	$12
S&P 500 Index**	100	114	115	129	157	150
S&P Mid Cap 400 Index	100	110	107	130	151	134
DJ U.S. Expl. & Prod. Index	100	89	68	85	86	71
ISE Revere Natural Gas Index	100	58	23	28	25	16

*The performance graph and the information contained in this section is not "soliciting material," is being "furnished" not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing.

**Our common stock is no longer a component of the S&P 500 Index but trades on the S&P Mid Cap 400 Index.

ITEM 6. SELECTED FINANCIAL DATA AND PROVED RESERVE DATA

The following table shows selected financial information as of and for the five years ended December 31, 2018. Significant producing property acquisitions and dispositions may affect the comparability of year-to-year financial and operating data. In fourth quarter 2018, we sold a proportionately reduced 1% overriding royalty in our Washington County, Pennsylvania leases for proceeds of $300.0 million. In September 2016, we completed the MRD Merger. In first quarter 2016, we sold our non-operated interest in certain wells and gathering facilities in northeast Pennsylvania for cash proceeds of $111.5 million. In fourth quarter 2015, we sold the majority of our Virginia and West Virginia properties for cash proceeds of $876.0 million, before closing adjustments. In the first half of 2014, we completed the Conger Exchange where we sold our Conger properties located in Glasscock and Sterling Counties, Texas in exchange for producing properties and other assets in Virginia and $145.0 million in cash, before closing adjustments. This information should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and our consolidated financial statements and related notes included elsewhere in this report (in thousands except per share or per mcfe data).

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Statements of Operations Data:					
Natural gas, NGLs and oil sales	$2,851,577	$2,176,287	$1,197,215	$1,089,644	$1,911,989
Total revenues and other income	3,282,645	2,611,030	1,099,939	1,598,068	2,426,057
Total costs and expenses	5,059,615	2,528,910	1,902,077	2,650,430	1,395,172
Net (loss) income	(1,746,481)	333,146	(521,388)	(713,685)	634,382
Net (loss) income per share:					
–Basic	(7.10)	1.34	(2.75)	(4.29)	3.81
–Diluted	(7.10)	1.34	(2.75)	(4.29)	3.79
Costs per mcfe: (a)					
Direct operating expense	$0.17	$0.18	$0.17	$0.27	$0.35
Production and ad valorem tax expense	0.06	0.06	0.05	0.07	0.11
General and administrative expense	0.26	0.32	0.33	0.38	0.50
Interest expense	0.26	0.27	0.30	0.33	0.40
Depletion, depreciation and amortization expense	0.79	0.85	0.93	1.14	1.30
	$1.54	$1.68	$1.78	$2.19	$2.66
Average Daily Production:					
Natural gas (mcf)	1,501,604	1,343,160	1,026,807	993,662	786,099
NGLs (bbls)	105,001	97,834	76,026	55,770	51,563
Oil (bbls)	11,585	13,115	9,861	11,189	11,150
Total mcfe (b)	2,201,117	2,008,852	1,542,132	1,395,419	1,162,374
Balance Sheet Data:					
Current assets (c)	$602,185	$429,234	$281,883	$439,074	$570,292
Current liabilities (d)	754,811	755,473	702,653	351,720	639,677
Natural gas and oil properties, net	9,023,185	9,566,737	9,256,337	6,361,305	7,977,573
Total assets	9,708,154	11,728,841	11,282,245	6,900,031	8,704,604
Bank debt	932,018	1,208,467	876,428	86,427	713,221
Senior notes	2,856,166	2,851,754	2,848,591	738,101	—
Senior subordinated notes	48,677	48,585	48,498	1,826,775	2,317,603

Stockholders' equity	4,059,431	5,774,272	5,408,368	2,759,658	3,457,429
Weighted average diluted shares outstanding	246,171	245,458	189,868	166,389	164,403
Cash dividends declared per common share	0.08	0.08	0.08	0.16	0.16
Statements of Cash Flows Data:					
Net cash provided from operating activities	$990,690	$816,254	$387,068	$691,402	$974,353
Net cash used in investing activities	(695,434)	(1,139,057)	(308,835)	(218,772)	(1,245,456)
Net cash (used in) provided from financing activities	(295,159)	322,937	(78,390)	(472,607)	271,203
Proved Reserves Data (at end of period):					
Natural gas (Bcf)	12,028	10,264	7,870	6,278	6,923
NGLs (Mmbbls)	922	763	630	549	516
Oil and condensate (Mmbbls)	86	70	70	53	49
Total proved reserves (Bcfe)	18,072	15,262	12,072	9,892	10,310

(a) These are costs we believe fluctuate on a unit-of-production or per mcfe basis.

(b) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate energy content of oil and natural gas, which is not indicative of the relationship between oil and natural gas prices.

(c) 2018 includes $88.0 million of derivative assets compared to $58.6 million in 2017, $13.3 million in 2016, $281.5 million in 2015 and $363.0 million in 2014.

(d) 2018 includes $4.1 million of derivative liabilities compared to $44.2 million in 2017, $165.0 million in 2016 and $1.1 million in 2015.

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. The following discussion should be read in conjunction with the information under Item 8. Financial Statements and Supplementary Data and the other financial information found elsewhere in this Form 10-K. See also matters referenced in the foregoing pages under "Disclosures Regarding Forward-Looking Statements".

Overview of Our Business

We are an independent natural gas, natural gas liquids ("NGLs,") crude oil and condensate company engaged in the exploration, development and acquisition of natural gas and crude oil properties located primarily in the Appalachian and North Louisiana regions of the United States. We operate in one segment and have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our overarching business objective is to build stockholder value through returns focused growth of both reserves and production, on a per share debt-adjusted basis. Our strategy to achieve our business objective is to increase reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions and divestitures of non-core assets. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas, NGLs, crude oil and condensate and on our ability to economically find, develop, acquire and produce natural gas, NGLs and oil reserves. Looking to the future, our goal is to target annual production growth within operating cash flows. A further or extended decline in commodity prices could materially and adversely affect our business financial condition and results of operations. Prices for natural gas, NGLs, crude oil and condensate fluctuate widely and affect:

- our revenues, profitability and cash flow;
- the quantity of natural gas, NGLs and oil that we can economically produce;
- the quantity of natural gas, NGLs and oil shown as proved reserves;
- the amount of cash flow available to us for capital expenditures; and
- our ability to borrow and raise additional capital.

We prepare our financial statements in conformity with generally accepted accounting principles, which require us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved natural gas, NGLs and oil reserves. We use the successful efforts method of accounting for our natural gas, NGLs and oil activities. Our corporate headquarters is located in Fort Worth, Texas.

Sources of Our Revenues

We derive our revenues from the sale of natural gas, NGLs, crude oil and condensate that is produced from our properties. Revenues from product sales are a function of the volumes produced, prevailing market prices, product quality, gas Btu content and transportation costs. Our revenues are generally recognized at the point in time that control of the product is transferred to the customer and collectability is reasonably assured. Cash settlements of derivative contracts are included in derivative fair value in the accompanying statements of operations. Brokered natural gas, marketing and other revenues include revenue we receive as a result of selling natural gas that is not our production (brokered), revenue from the release of transportation capacity where we have taken capacity ahead of our production and marketing fees we receive from third parties.

Principal Components of Our Cost Structure

- Direct operating. These are day-to-day costs incurred to bring hydrocarbons out of the ground along with the daily costs incurred to maintain our producing properties. Such costs include compensation of our field employees, maintenance, repairs and workover expenses related to our natural gas and oil properties. The majority of these costs are expected to remain a function of supply and demand. Direct operating expenses also include stock-based compensation expense (non-cash) associated with the amortization of equity grants as part of the compensation of field employees.
- Transportation, gathering, processing and compression. Under some of our sales arrangements, we sell natural gas and NGLs at a specific delivery point, pay transportation, gathering, processing and compression costs to a third party and receive proceeds from the purchaser with no deduction. Transportation, gathering, processing and compression expense represents costs paid by Range to third parties under these arrangements.
- Production and ad valorem taxes. Production taxes are paid on produced natural gas and oil based on a percentage of sales revenue (excluding derivatives) or at fixed rates established by the applicable federal, state or

local taxing authorities. In some states, ad valorem taxes are generally based on reserve values at the end of each year. In Louisiana, ad valorem tax assessments are based on capital costs, well age, depth and production. The Pennsylvania impact fee on unconventional natural gas and oil production, which includes the Marcellus Shale, is also included in this category.

- Brokered natural gas and marketing. These expenses are gas purchases for brokered natural gas that we buy and sell that is not our production plus overhead, including payroll and benefits for our marketing staff. These expenses also include costs related to transportation capacity we have taken ahead of our production. Brokered natural gas and marketing expenses also include stock-based compensation expense (non-cash) associated with the amortization of equity grants as part of our marketing staff compensation.
- Exploration. These are geological and geophysical costs, such as payroll and benefits for the geological and geophysical staff, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes. Exploration expenses also include stock-based compensation expense (non-cash) associated with the amortization of equity grants as part of the compensation of our exploration staff.
- Abandonment and impairment of unproved properties. This category includes unproved property impairment expense associated with oil and gas lease expirations, shifts in business strategy which may impact the number of drilling locations or changing economic factors. Impairment on a majority of our unproved properties is assessed and amortized on an aggregate basis based on average holding period, expected forfeiture rate and anticipated drilling success.
- General and administrative. These costs include overhead, such as payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees, legal compliance and legal settlements. Included in this category are overhead expense reimbursements we receive from working interest owners of properties, for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property’s life. General and administrative expenses also include stock-based compensation expense (non-cash) associated with the amortization of equity grants as part of the compensation of our corporate staff and our directors.
- Deferred compensation plan. These costs relate to the increase or decrease in the value of the liability associated with our deferred compensation plan. Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in our common stock or make other investments at the individual’s discretion. The assets of this plan are held in a grantor trust, are funded on the grant date and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. We do not maintain a defined benefit retirement plan for any of our employees. However, in fourth quarter 2017, we implemented a succession plan enhancement for officers which includes a post-retirement benefit plan to assist in providing health care to officers who are active employees and have met certain age and service requirements. These benefits are provided up to age 65 or at the date they become eligible for Medicare.
- Interest. We have typically financed a portion of our cash requirements with borrowings under our bank credit facility and with longer-term debt securities. Also included are administrative fees associated with our bank credit facility and the amortization of deferred financing costs. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We currently have no capitalized interest.
- Depreciation, depletion and amortization. This includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This expense also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines, and other facilities.
- Income taxes. We are subject to state and federal income taxes but are currently not in a cash taxpaying position for federal income taxes, primarily due to the current deductibility and/or accelerated amortization of intangible drilling costs (“IDC”). At this time, we generally do not pay significant state income taxes due to our state net operating loss carryovers and our ability to follow the federal treatment of deducting IDC in most of the states in which we operate. Currently, all of our federal taxes are deferred. As of December 31, 2018, we have federal valuation

allowances of $19.0 million and state valuation allowances of $101.4 million. For more information, see Item 1A. Risk Factors-Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated or postponed and additional federal or state taxes on natural gas extraction may be imposed, as a result of future legislation.

Management’s Discussion and Analysis of Results of Operations

Commodity prices have remained volatile but improved during 2018 compared to fourth quarter 2017. While operating in this improving price environment, we had many operational, financial and strategic successes in 2018. During 2018, we continued our focus on enhancing margins and returns, driving operational efficiencies, simplifying our portfolio and maintaining liquidity. We believe we have positioned ourselves for long-term success through the natural gas and oil business cycle and growth at financially attractive rates of return. In summary, we exited 2018 with operational momentum, investment flexibility and a robust financial liquidity position, which we expect to carry over to 2019.

Overview of 2018 Results

For the year ended December 31, 2018, we experienced an increase in revenue from the sale of natural gas, NGLs and oil due to 2% increase in net realized prices (average prices including all derivative settlements and third-party transportation costs paid by us) and 10% higher production volumes when compared to 2017. Daily production in 2018 averaged 2.2 Bcfe compared to 2.0 Bcfe in 2017 as a result of drilling and completions in Pennsylvania. Average natural gas differentials improved $0.32 per mcf while operating costs were higher when compared to 2017.

During 2018, we recognized net loss of $1.7 billion, or $7.10 per diluted common share compared to net income of $333.1 million, or $1.34 per diluted common share during 2017. The decrease in net income is primarily due to a $1.6 billion impairment of goodwill, higher abandonment and impairment of unproved property expenses and unfavorable derivative fair value income (or the non-cash fair value adjustment related to our derivatives). Prior year income taxes included a one-time tax benefit of $334.0 million resulting from the 2017 Tax Act.

During 2018, we achieved the following financial and operating performance results:

- average realized prices improved 2% from 2017;
- 10% production growth from 2017;
- achieved 18% annual proved reserve growth with a 55% increase in the standardized after-tax measure of discounted future net cash flows when compared to 2017;
- capital spending was 3% lower than original 2018 budget;
- drilled 101.7 net wells with a 100% success rate;
- continued expansion of our activities in the Marcellus Shale by growing production, proving up acreage and acquiring additional unproved acreage;
- reduced general and administrative expenses per mcfe 19% from 2017;
- reduced interest expense per mcfe 4% from 2017;
- reduced our DD&A rate per mcfe 7% from 2017;
- reduced total debt by $271.9 million;
- achieved a debt per mcfe of proved reserves of $0.21 compared to $0.27 in 2017;
- entered into additional commodity-based derivative contracts for 2019 and 2020;
- received $323.3 million of proceeds, before closing adjustments, from the sale of a proportionately reduced 1% overriding royalty in our Washington County, Pennsylvania properties and producing properties in Oklahoma and $1.2 million of proceeds from the sale of miscellaneous non-core oil and gas assets;
- continued to enter into new marketing agreements to improve our realized prices;
- realized $990.7 million of cash flow from operating activities; and
- ended the year with stockholders' equity of $4.1 billion.

Operationally, in 2018 we continued to focus on operational flexibility, efficiencies and controlling costs. As evidenced by history and our current industry environment, the prices at which we sell our production are volatile and we have little control over them. Therefore, to improve our profitability, we focus our efforts on improving operating efficiency. We continue to focus on material reductions in unit costs. As reservoirs are depleted and production rates decline, per unit production costs will generally increase. To lessen this effect, we concentrate our production in core areas where we can achieve economies of scale to help manage our operating costs.

We generated $990.7 million of cash flow from operating activities in 2018, an increase of $174.4 million from 2017 which reflects improvements in realized prices and higher production volumes and lower comparative working capital outflows ($8.2 million outflow during 2018 compared to $47.2 million outflow in 2017). We ended the year with $775.6 million of available committed borrowing capacity, with an additional $1.0 billion in borrowing base capacity available.

Acquisitions

During 2018, we spent $62.4 million to acquire unproved acreage compared to $62.1 million in 2017 and $33.1 million in 2016. We continue selective acreage leasing and lease renewals to consolidate our acreage positions in both the Marcellus Shale play in Pennsylvania and North Louisiana.

Divestitures

Pennsylvania. In fourth quarter 2018, we sold a proportionately reduced 1% overriding royalty in our Washington County, Pennsylvania leases for gross proceeds of $300.0 million and we recorded a loss of $10.2 million, after fees and closing adjustments. In first quarter 2016, we sold our non-operated interest in certain wells and gathering facilities in northeast Pennsylvania for proceeds of $111.5 million and we recorded a loss of $2.1 million, after closing adjustments.

Oklahoma. In 2018, we sold various properties in Northern Oklahoma for proceeds of $23.3 million and we recognized a net loss of $39,000, after closing adjustments. In 2017, we sold various properties in Western Oklahoma for proceeds of $30.8 million and we recognized a gain of $23.8 million, after closing adjustments. In 2016, we sold certain properties in Western Oklahoma for proceeds of $78.6 million and we recorded a loss of $5.3 million related to these sales, after closing adjustments and transaction fees.

Texas. In 2017, we sold various properties for proceeds of $40.4 million and we recognized a loss of $989,000, after closing adjustments.

2019 Outlook

As we enter 2019, we believe we are positioned for sustainable long-term success and operational efficiencies. For 2019, our board of directors approved a $756.0 million capital budget for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. Our 2019 capital budget is approximately 90% allocated to our Appalachian division. As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices, drilling success and other factors. We also expect our 2019 capital budget to achieve production growth of approximately 6% as we limit capital spending to at or below cash flow. Our 2019 capital budget is designed to focus on continuing to improve corporate returns and generating free cash flow. To the extent commodity prices decline, we may reduce the capital budget with the intent of limiting capital spending to at or below cash flow. The prices we receive for our natural gas, NGLs and oil production are largely based on current market prices, which are beyond our control. The price risk on a portion of our forecasted natural gas, NGLs and oil production for 2019 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions. We believe it is likely commodity prices will continue to be volatile during 2019.

Market Conditions

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Prices for commodities, such as hydrocarbons, are inherently volatile. Modest commodity price improvement has increased our average realized prices. Recently, natural gas prices have decrease, when compared to December 2018, with the average NYMEX monthly settlement price for natural gas decreasing to $2.95 per mcf for February 2019. Crude oil prices have increased, when compared to December 2018, to $51.55 per barrel in January 2019. The following table lists related benchmarks for natural gas, oil and NGLs composite prices for the years ended December 31, 2018, 2017 and 2016.

	Year Ended December 31,		
	2018	2017	2016
Benchmarks			
Average NYMEX prices [a]			
Natural gas (per mcf)	$3.07	$3.10	$2.51
Oil (per bbl)	$65.49	$51.07	$43.69
Mont Belvieu NGL composite (per gallon) [b]	$0.67	$0.56	$0.41

[a] Based on average of bid week prompt month prices on the New York Mercantile Exchange (“NYMEX”).

[b] Based on our estimated NGLs product composition per barrel.

Our price realization may differ from the benchmarks for many reasons, including quality, location, or production being sold at different indices.

Adoption of New Accounting Standard

On January 1, 2018, we adopted the new revenue recognition accounting standards update. As a result of this adoption, we have modified our presentation of certain gas processing contracts. Results for reporting periods beginning after January 1, 2018 are presented based on the new accounting standards while prior period amounts are not adjusted and continue to be reported in accordance with our historical accounting. For additional information, see Note 3 and Note 5 to the consolidated financial statements. The impact of adoption of the new revenue recognition standard for the year ended December 31, 2018 is as follows (in thousands):

	Year Ended December 31, 2018	
	As Reported	Previous Revenue Recognition Method
Natural gas, NGLs and oil sales		
Natural gas	$1,663,832	$1,663,832
NGLs	931,360	758,561
Oil	255,885	255,885
Total	$2,851,077	$2,678,278
Transportation, gathering, processing and compression		
Natural gas	$678,489	$678,489
NGLs	439,327	266,528
Total	$1,117,816	$945,017
Net loss	$(1,746,481)	$(1,746,481)

See Note 3 for a discussion of new accounting standards that affect us.

Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations

Our revenues vary from year to year as a result of changes in realized commodity prices and production volumes. For more information, see “Sources of Our Revenues” above. In 2018, natural gas, NGLs and oil sales increased 31% from 2017 with a 10% increase in production and a 20% increase in realized prices (excluding cash settlements on our derivatives). NGLs sales for the current year includes the impact of the adoption of the new revenue standard, as described above. In 2017, natural gas, NGLs and oil sales increased 82% from 2016 with a 30% increase in production and a 40% increase in realized prices (before cash settlements on our derivatives). The following table illustrates the primary components of natural gas, NGLs, crude oil and condensate sales for each of the last three years (in thousands):

	2018	2017	2016
Natural gas, NGLs and Oil sales			
Natural gas	$1,663,832	$1,349,965	$753,888
NGLs	931,360	604,672	318,462
Oil and condensate	255,885	221,650	124,865
Total natural gas, NGLs and oil sales	$2,851,077	$2,176,287	$1,197,215

Our production continues to grow through drilling success as we place new wells on production partially offset the natural decline of our natural gas and oil reserves through production and non-core asset sales. For 2018, our production increased 18% in our Appalachian region when compared to 2017. For 2017, our production increased 16% in our Appalachian region when compared to 2016. Production from our newly acquired North Louisiana properties was 110.6 Bcfe in 2018 compared to 138.7 Bcfe in 2017 and 43.6 Bcfe in 2016. Our production for each of the last three years is set forth in the following table:

	2018	2017	2016
Production [(a)]			
Natural gas (mcf)	548,085,437	490,253,467	375,811,462
NGLs (bbls)	38,325,251	35,709,254	27,825,635
Crude oil and condensate (bbls)	4,228,439	4,787,022	3,609,171
Total (mcfe) [(b)]	803,407,577	733,231,123	564,420,298
Average daily production [(a)]			
Natural gas (mcf)	1,501,604	1,343,160	1,026,807
NGLs (bbls)	105,001	97,834	76,026
Crude oil and condensate (bbls)	11,585	13,115	9,861
Total (mcfe) [(b)]	2,201,117	2,008,852	1,542,132

(a) Represents volumes sold regardless of when produced.

(b) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship between oil and natural gas prices.

Our average realized price (including all derivative settlements and third-party transportation costs paid by Range) received during 2018 was $1.99 per mcfe compared to $1.95 per mcfe in 2017 and $1.74 per mcfe in 2016. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices should include the impact of transportation, gathering, processing and compression expense. Average sales prices (excluding derivative settlements) do not include any derivative settlements or third-party transportation costs which are reported in transportation, gathering and compression expense on the accompanying consolidated statements of operations. Average sales prices (excluding derivative settlements) do include transportation costs where we receive net proceeds from the purchaser. Our average realized price (including all derivative settlements and third-party transportation costs paid by Range) calculation includes all cash settlements for derivatives. Average realized price calculations for each of the last three years are shown below:

	2018	2017	2016
Average Prices			
Average sales prices (excluding derivative settlements):			
Natural gas (per mcf)	$3.04	$2.75	$2.01
NGLs (per bbl)	24.30	16.93	11.44
Crude oil (per bbl)	60.52	46.30	34.60
Total (per mcfe) [(a)]	3.55	2.97	2.12
Average realized prices (including all derivative settlements):			
Natural gas (per mcf)	$2.98	$2.90	$2.68
NGLs (per bbl)	22.62	14.88	13.16
Crude oil (per bbl)	51.60	49.49	47.82
Total (per mcfe) [(a)]	3.39	2.99	2.74
Average realized prices (including all derivative settlements and third-party transportation costs paid by Range):			
Natural gas (per mcf)	$1.74	$1.82	$1.60
NGLs (per bbl)	11.15	8.32	7.33
Crude oil (per bbl)	51.60	49.49	47.82

Total (per mcfe) [a]	1.99	1.95	1.74

[a] Oil and NGLs are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil to natural gas, which is not indicative of the relationship between oil and natural gas prices.

Realized prices include the impact of basis differentials and gains or losses realized from our basis hedging. The prices we receive for our natural gas can be more or less than the NYMEX price because of adjustments for delivery location, relative quality and other factors. The following table provides this impact on a per mcf basis:

	Year Ended December 31, 2018	2017	2016
Average natural gas differentials below NYMEX	$(0.03)	$(0.35)	$(0.52)
Realized (losses) gains on basis hedging	$(0.02)	$0.03	$0.05

The following tables reflect our production and average realized commodity prices (excluding derivative settlements and third-party transportation costs paid by Range) (in thousands, except prices):

	Year Ended December 31, 2017	Price Variance	Volume Variance	2018	Year Ended December 31, 2016	Price Variance	Volume Variance	2017
Natural gas								
Price (per mcf)	$2.75	$0.29	$—	$3.04	$2.01	$0.74	$—	$2.75
Production (Mmcf)	490,253	—	57,832	548,085	375,811	—	114,442	490,253
Natural gas sales	$1,349,965	$154,621	$159,246	$1,663,832	$753,888	$366,503	$229,574	$1,349,965

	Year Ended December 31, 2017	Price Variance	Volume Variance	2018	Year Ended December 31, 2016	Price Variance	Volume Variance	2017
NGLs								
Price (per bbl)	$16.93	$7.37	$—	$24.30	$11.44	$5.49	$—	$16.93
Production (Mbbls)	35,709	—	2,616	38,325	27,826	—	7,883	35,709
NGLs sales	$604,672	$282,390	$44,298	$931,360	$318,462	$195,983	$90,227	$604,672

	Year Ended December 31, 2017	Price Variance	Volume Variance	2018	Year Ended December 31, 2016	Price Variance	Volume Variance	2017
Crude oil								
Price (per bbl)	$46.30	$14.22	$—	$60.52	$34.60	$11.70	$—	$46.30
Production (Mbbls)	4,787	—	(559)	4,228	3,609	—	1,178	4,787
Crude oil sales	$221,650	$60,099	$(25,864)	$255,885	$124,865	$56,035	$40,750	$221,650

	Year Ended December 31, 2017	Price Variance	Volume Variance	2018	Year Ended December 31, 2016	Price Variance	Volume Variance	2017
Consolidated								
Price (per mcfe)	$2.97	$0.58	$—	$3.55	$2.12	$0.85	$—	$2.97
Production (Mmcfe)	733,231	—	70,177	803,408	564,420	—	168,811	733,231
Total natural gas, NGLs and oil sales	$2,176,287	$466,501	$208,289	$2,851,077	$1,197,215	$621,000	$358,072	$2,176,287

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Transportation, gathering, processing and compression expense was $1.1 billion in 2018 compared to $761.2 million in 2017 and $565.2 million in 2016. These third-party costs are higher in each year due to our production growth in the Marcellus Shale where we have third-party gathering, compression, processing and transportation agreements. Additionally, we experienced higher costs resulting from our adoption of the new revenue standard (as detailed above), new in-service pipelines, higher NGLs costs due to higher production and prices and higher NGLs expense in North Louisiana due to fully utilizing amounts that were previously accrued for capacity commitments. The year ended December 31, 2017 includes additional third-party costs for our newly acquired North Louisiana production for the entire year. We have included these costs in the calculation of average realized prices (including all derivative settlements and third-party transportation expenses paid by Range). The following table summarizes transportation, gathering, processing and compression expense for each of the last three years (in thousands) and on a per mcf and per barrel basis:

	2018	2017	2016
Natural gas	$ 678,489	$ 526,671	$ 403,209
NGLs	439,327	234,512	162,000
Total	$1,117,816	$761,183	$565,209
Natural gas (per mcf)	$1.24	$1.07	$1.07
NGLs (per bbl)	$11.46	$6.57	$5.82

Derivative fair value (loss) income was a loss of $51.2 million in 2018 compared to income of $213.4 million in 2017 and a loss of $261.4 million in 2016. All of our derivatives are accounted for using the mark-to-market accounting method. Mark-to-market accounting treatment creates volatility in our revenues as unrealized gains and losses from derivatives are included in total revenues. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Gains on our derivatives generally indicate lower wellhead revenues in the future while losses indicate higher future wellhead revenues. At December 31, 2018, our commodity derivative contracts were recorded at their fair value, which was a net derivative asset of $80.9 million, an increase of $67.3 million from the $13.6 million net derivative asset recorded as of December 31, 2017. We have also entered into basis swap agreements to limit volatility caused by changing differentials between NYMEX and regional prices received. These basis swaps are marked to market and we recognized a net derivative asset of $4.8 million as of December 31, 2018 compared to a net derivative liability of $7.8 million as of December 31, 2017. As of December 31, 2018, we have propane basis swaps to limit the volatility caused by changing differentials between Mont Belvieu and international propane indexes which is recognized as a net derivative asset of $117,000 as of December 31, 2018 compared to a net derivative liability of $1.2 million as of December 31, 2017. In connection with our international propane swaps, we also have freight swap contracts which lock in the freight rate for a specific trade route on the Baltic Exchange which is recognized as a net derivative liability of $561,000 compared to a net derivative asset of $276,000 as of December 31, 2017. The following table summarizes the impact of our commodity derivatives for each of the last three years (in thousands):

	2018	2017	2016
Derivative fair value (loss) income per consolidated statements of operations	$(51,192)	$213,350	$(261,391)
Non-cash fair value gain (loss): [1]			
Natural gas derivatives	$(84,889)	$221,251	$(415,833)
Oil derivatives	57,149	(20,874)	(30,363)
NGLs derivatives	108,908	(355)	(149,982)
Freight derivatives	(838)	211	(12,549)
Total non-cash fair value gain (loss) [1]	$80,330	$200,233	$(608,727)
Net cash (payment) receipt on derivative settlements:			
Natural gas derivatives	$(29,291)	$71,059	$252,000

Oil derivatives	(37,709)	15,250	47,710
NGLs derivatives	(64,522)	(73,192)	47,626
Total net cash (payment) receipt	$(131,522)	$13,117	$347,336

(1) Non-cash fair value adjustments on commodity derivatives is a non-GAAP measure. Non-cash fair value adjustments on commodity derivatives only represent the net change between periods of the fair market values of commodity derivative positions and exclude the impact of settlements on commodity derivatives during the period. We believe that non-cash fair value adjustments on commodity derivatives is a useful supplemental disclosure to differentiate non-cash fair market value adjustments from settlements on commodity derivatives during the period. Non-cash fair value adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered a substitute for derivative fair value income or loss as reported in our consolidated statements of operations.

Brokered natural gas, marketing and other revenue was $482.8 million in 2018 compared to $221.4 million in 2017 and $164.1 million in 2016. The 2018 period includes $460.3 million of revenue from the sale of natural gas that is not related to our production (brokered) and $9.0 million of revenue from the sale of NGLs that is not related to our production. These revenues both increased due to higher brokered volumes and higher sales prices. In addition, fourth quarter 2018 included production volume shortfall due to third-party processing facility plant repairs with additional volumes being purchased and sold to satisfy our commitments. The 2017 period includes $219.5 million of revenue primarily from the sale of natural gas that is not related to our production. These revenues increased from 2016 due to higher brokered natural gas volumes and higher sales prices. The 2016 period includes $163.2 million of revenue primarily from the sale of natural gas that is not related to our production (brokered). These revenues increased from 2015 due to significantly higher brokered natural gas volumes and higher sales prices.

Costs and Expenses per mcfe

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about certain of our expenses on a per mcfe basis for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2018	2017	Change	% Change	2017	2016	Change	% Change
Direct operating expense	$0.17	$0.18	$(0.01)	(6%)	$0.18	$0.17	$0.01	6%
Production and ad valorem tax expense	0.06	0.06	—	—%	0.06	0.05	0.01	20%
General and administrative expense	0.26	0.32	(0.06)	(19%)	0.32	0.33	(0.01)	(3%)
Interest expense	0.26	0.27	(0.01)	(4%)	0.27	0.30	(0.03)	(10%)
Depletion, depreciation and amortization expense	0.79	0.85	(0.06)	(7%)	0.85	0.93	(0.08)	(9%)

Direct operating expense was $139.5 million in 2018 compared to $134.3 million in 2017 and $97.4 million in 2016. We experience increases in operating expenses as we add new wells and manage existing properties. Direct operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workovers and repair-related expenses. On an absolute basis, our direct operating expenses for 2018 increased 4% from the prior year primarily due to higher water hauling/handling costs partially offset by the sale of certain non-core assets. On an absolute basis, our direct operating expenses for 2017 increased 38% from the prior year primarily due to our newly acquired North Louisiana properties partially offset by our continuing cost reduction efforts. In 2017, we experienced cost increases in many categories of direct operating expenses including personnel costs, well service costs, water handling and disposal costs and workovers. We incurred $9.8 million of workover costs in 2018 compared to $10.5 million of workover costs in 2017 and $4.5 million in 2016.

On a per mcfe basis, operating expense for 2018 decreased $0.01, or 6% from the same period of 2017, with the decrease due to higher production volumes and the sale of certain non-core assets. On a per mcfe basis, operating expense for 2017 increased $0.01, or 6%, from the same period of 2016, with the increase consisting of higher water handling and equipment leasing costs. We have experienced lower costs per mcfe as we have increased production from our Marcellus Shale wells due to their lower operating cost relative to our other operating areas. Stock-based compensation expense represents the amortization of equity grants as part of the compensation of field employees. The following table summarizes direct operating expenses per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2018	2017	Change	% Change	2017	2016	Change	% Change
Lease operating expense	$0.16	$0.17	$(0.01)	(6%)	$0.17	$0.16	$0.01	6%
Workovers	0.01	0.01	—	—%	0.01	0.01	—	—%
Stock-based compensation (non-cash)	—	—	—	—%	—	—	—	—%
Total direct operating expense	$0.17	$0.18	$(0.01)	(6%)	$0.18	$0.17	$0.01	6%

Production and ad valorem taxes are paid based on market prices, not hedged prices. This expense category also includes the Pennsylvania impact fee. In February 2012, the Commonwealth of Pennsylvania enacted an “impact fee” on unconventional natural gas and oil production which includes the Marcellus Shale. The impact fee is based upon the year wells are drilled and the fee varies, like a severance tax, based upon natural gas prices. The year ended December 31, 2018 includes a $32.4 million impact fee compared to $30.9 million in the year ended December 31, 2017 with an increase in wells subject to the impact fee. The year ended December 31, 2017 includes a $30.9 million impact fee compared to $22.5 million in the year ended December 31, 2016 with an increase in wells drilled in Pennsylvania and higher prices. Production and ad valorem taxes (excluding the impact fee) were $13.7 million compared to $11.9 million in 2017 due to higher prices. Production and ad valorem taxes (excluding the impact fee) were $11.9 million in 2017 compared to $2.9 million in 2016 primarily due to the addition of our newly acquired North Louisiana properties. The following table summarizes production and ad valorem taxes per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2018	2017	Change	% Change	2017	2016	Change	% Change
Production taxes	$0.01	$0.01	$—	— %	$0.01	$0.01	$—	— %
Ad valorem taxes	—	0.01	(0.01)	(100 %)	0.01	—	0.01	100 %
Impact fee	0.05	0.04	0.01	25 %	0.04	0.04	—	— %
Total production and ad valorem	$0.06	$0.06	$—	— %	$0.06	$0.05	$ 0.01	20 %

General and administrative expense was $209.8 million for 2018 compared to $233.4 million for 2017 and $184.8 million in 2016. The decrease in 2018, when compared to 2017, is primarily due to lower stock-based compensation of $31.1 million, lower bad debt expenses of $2.6 million and lower franchise taxes of $9.2 million which were partially offset by higher legal costs (including settlements), technology costs and salaries and benefits. The increase in 2017, when compared to 2016, is primarily due to higher stock-based compensation of $30.2 million resulting from accelerated vesting of equity awards related to a one-time implementation of a succession plan enhancement for officers, higher salaries and benefits of $7.6 million, higher legal costs (including settlements) of $5.0 million and higher Louisiana franchise taxes of $4.2 million. Stock-based compensation expense represents the amortization of stock-based compensation awards granted to our employees and directors as part of their compensation. The following table summarizes general and administrative expenses per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2018	2017	Change	% Change	2017	2016	Change	% Change
General and administrative	$0.21	$0.22	$ (0.01)	(5 %)	$0.22	$0.24	$ (0.02)	(8 %)
Stock-based compensation (non-cash)	0.05	0.10	(0.05)	(50 %)	0.10	0.09	0.01	11 %
Total general and administrative expense	$0.26	$0.32	$ (0.06)	(19 %)	$0.32	$0.33	$ (0.01)	(3 %)

Interest expense was $210.2 million for 2018 compared to $195.7 million for 2017 and $168.2 million in 2016. The following table presents information about interest expense per mcfe for each of the last three years:

	Year Ended December 31,		
	2018	2017	2016
Bank credit facility	$0.06	$0.05	$0.02
Senior notes	0.19	0.20	0.12
Senior subordinated notes	—	0.01	0.13
Senior note exchange	—	—	0.01
Amortization of deferred financing costs and other	0.01	0.01	0.02
Total interest expense	$0.26	$0.27	$0.30
Average debt outstanding (in thousands)	$4,182,340	$3,960,994	$3,052,666
Average interest rate [(a)]	4.9 %	4.8 %	5.1 %

(a) Includes commitment fees but excludes amortization of debt issue costs and amortization of discount.

On an absolute basis, the increase in interest expense for 2018 from the same period of 2017 was primarily due to higher average outstanding debt balances and slightly higher average interest rates. On an absolute basis, the increase in interest expense for 2017 from the same period of 2016 was primarily due to higher average outstanding debt balances partially offset by lower average interest rates. Interest expense in 2016 includes an additional $6.6 million of transaction costs associated with our senior subordinated note exchange. See Note 8 to our consolidated financial statements for additional information. Average debt outstanding on the bank credit facility for 2018 was $1.3 billion compared to $1.0 billion for 2017 and $356.6 million for 2016 and the weighted average interest rate on the bank credit facility was 3.7% for 2018 compared to 2.7% in 2017 and 2.2% in 2016.

Depletion, depreciation and amortization ("DD&A") was $635.5 million in 2018 compared to $625.0 million in 2017 and $524.1 million in 2016. The increase in 2018 when compared to 2017 is due to a 10% increase in production volumes somewhat offset by a 9% decrease in depletion rates. The increase in 2017 when compared to 2016 is due to a 30% increase in production volumes somewhat offset by a 7% decrease in depletion rates.

On a per mcfe basis, DD&A decreased to $0.79 in 2018 compared to $0.85 in 2017 and $0.93 in 2016. Depletion expense, the largest component of DD&A, was $0.75 per mcfe in 2018 compared to $0.82 per mcfe in 2017 and $0.88 per mcfe in 2016. We have historically adjusted our depletion rates in the fourth quarter of each year based on our year-end reserve report and at other times during the year when circumstances indicate there has been a significant change in reserves or costs. We currently expect our DD&A rate to be approximately $0.70 per mcfe in 2019, based on our current production estimates. In areas where we are actively drilling, such as the Marcellus Shale area, our fourth quarter adjusted 2018 depletion rates were lower than the fourth quarter 2017 and 2016 depletion rates. Depletion rates in new plays tend to be higher in the beginning as increased initial outlays are amortized over proved reserves based on early stages of evaluations. The decrease in DD&A per mcfe in 2018 when compared to 2017 and 2016 is due to the mix of our production from our properties with lower depletion rates. The following table summarizes DD&A expenses per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2018	2017	Change	% Change	2017	2016	Change	% Change
Depletion and amortization	$0.75	$0.82	$(0.07)	(9%)	$0.82	$0.88	$(0.06)	(7%)
Depreciation	0.01	0.01	—	—%	0.01	0.02	(0.01)	(50%)
Accretion and other	0.03	0.02	0.01	50%	0.02	0.03	(0.01)	(33%)
Total DD&A expenses	$0.79	$0.85	$(0.06)	(7%)	$0.85	$0.93	$(0.08)	(9%)

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, brokered natural gas and marketing, exploration expense, abandonment and impairment of unproved properties, MRD Merger expenses, termination costs, deferred compensation plan expenses, impairment of proved properties and impairment of goodwill.

The following table details stock-based compensation that is allocated to functional expense categories for each of the years in the three-year period ended December 31, 2018 (in thousands):

	2018	2017	2016
Direct operating expense	$2,109	$2,060	$2,302
Brokered natural gas and marketing expense	1,452	1,437	1,725
Exploration expense	1,921	2,128	2,298
Exploration expense – one-time acceleration	—	614	—
General and administrative expense	43,806	44,659	49,293
General and administrative expense – one-time acceleration	—	30,214	—
Termination costs	—	1,664	—
Total stock-based compensation	$49,288	$82,776	$55,618

Stock-based compensation includes the amortization of restricted stock grants, SARs and PSUs grants. The year ended 2017 includes $30.8 million in increased stock-based compensation due to accelerated vesting of existing equity awards related to the one-time implementation of a succession plan enhancement for officers.

Brokered natural gas and marketing expense was $496.0 million in 2018 compared to $220.3 million in 2017 and $168.6 million in 2016. The increase in these costs reflects significantly higher broker purchase volumes and higher purchase prices. The following table details our brokered natural gas, marketing and other net margin for each of the years in the three-year period ended December 31, 2018 (in thousands):

	2018	2017	2016
Brokered natural gas sales	$460,349	$204,316	$146,454

Brokered NGLs sales	9,018	1,105	8,878
Other marketing revenue	13,393	15,972	8,783
Brokered natural gas purchases and transportation	(477,962)	(210,142)	(149,654)
Brokered NGLs purchases	(7,727)	(964)	(8,481)
Other marketing expense	(10,358)	(9,205)	(10,441)
Net brokered natural gas and marketing net margin	$(13,287)	$1,082	$(4,461)

Exploration expense was $34.1 million in 2018 compared to $53.7 million in 2017 and $32.3 million in 2016. Exploration expense in 2018 was lower due to lower dry hole costs and lower seismic costs. Exploration expense was higher in 2017 when compared to 2016 due to higher dry hole costs, higher seismic costs and higher delay rentals. Stock-based compensation represents the amortization of equity stock grants as part of the compensation of our exploration staff. The following table details our exploration related expenses for each of the years in the three-year period ended December 31, 2018 (in thousands):

	Year Ended December 31,				Year Ended December 31,			
	2018	2017	Change	% Change	2017	2016	Change	% Change
Seismic	$67	$15,191	$(15,124)	(100 %)	$15,191	$9,793	$5,398	55 %
Delay rentals and other	19,742	14,658	5,084	35 %	14,658	9,489	5,169	54 %
Personnel expense	12,383	11,899	484	4 %	11,899	10,727	1,172	11 %
Stock-based compensation expense	1,921	2,742	(821)	(30 %)	2,742	2,298	444	19 %
Exploratory dry hole expense	4	9,172	(9,168)	(100 %)	9,172	18	9,154	— %
Total exploration expense	$34,117	$53,662	$(19,545)	(36 %)	$53,662	$32,325	$21,337	66 %

Abandonment and impairment of unproved properties was $515.0 million in 2018 compared to $269.7 million in 2017 and $30.1 million in 2016. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. In certain circumstances, our future plans to develop acreage may accelerate our impairment. In 2018, an impairment of $436.0 million was recorded related to unproved property value allocated in the MRD Merger related to probable and possible reserves that we no longer have the intent to drill based on a shift in capital allocation which materially impacted our drilling inventory. The increase in abandonment expense from 2016 to 2017 reflects additional lease expirations in North Louisiana. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments may be recorded.

MRD Merger expenses of $37.2 million in 2016 included amounts paid in connection with the MRD Merger including consulting, investment banking, advisory, legal and other merger-related fees. There were no MRD Merger expenses in 2017 or 2018.

Termination costs in 2018 includes favorable severance accrual adjustments of $373,000 compared to $3.8 million expense in 2017 as we implemented additional work force reductions with $2.2 million for estimated severance costs and $1.7 million of accelerated vesting of equity grants. Termination costs in 2016 included additional accrued leasing costs related to the closing of our Oklahoma City offices more than offset by favorable severance adjustments.

Deferred compensation plan expense was a gain of $18.6 million in 2018 compared to a gain of $50.9 million in 2017 and a loss of $19.2 million in 2016. Our stock price decreased to $9.57 at December 31, 2018 from $17.06 at December 31, 2017. Our stock price decreased to $17.06 at December 31, 2017 from $34.36 at December 31, 2016. This non-cash item relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in our deferred compensation plan. The deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense. Common shares are placed in the deferred compensation plan when granted.

Impairment of proved properties decreased to $22.6 million in 2018 compared to $63.7 million in 2017 and $43.0 million in 2016. In 2018, we recorded impairment expense related to certain non-core properties in Northwest Pennsylvania and certain of our oil and gas properties in Oklahoma. During 2018, we increased our interest in certain properties in our shallow legacy assets in Northwest Pennsylvania for a minimal dollar amount for which the fair value was previously determined to be zero. As a result, we recorded impairment expense of $15.3 million related to these Northwest Pennsylvania assets. In, 2018 our Oklahoma assets were evaluated for impairment due to the possibility of sale. In 2017, we recorded impairment expense related to certain of our oil and gas properties in Oklahoma and the Texas Panhandle. These assets were evaluated for impairment due to the possibility of sale. In 2016, we recorded impairment expense related to certain of our oil and gas properties in Western Oklahoma. These assets were evaluated for impairment due to commodity prices and the possibility of sale. The cash flows we use to assess proved property impairment include numerous assumptions including (1) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (2) results of future drilling activities, (3) future commodity prices and (4) increases or decreases in production and capital costs. All inputs are evaluated at each measurement date.

Impairment of goodwill was $1.6 billion in 2018. During fourth quarter 2018, due to the significant decline in our stock price, we performed a quantitative impairment assessment of our goodwill. Fair value was estimated based on a combination of a market and an income approach. Goodwill is related to the excess purchase price over amounts assigned to assets acquired and liabilities assumed in the MRD Merger. Our estimate of fair value required us to use significant unobservable inputs including assumptions for commodity prices, production, forward pricing curves, operating and development costs and other factors. Based on this analysis, we determined the fair value of goodwill was zero and goodwill was fully impaired.

Income tax benefit was $30.5 million in 2018 compared to $251.0 million in 2017 and $280.8 million in 2016. The 2018 decrease reflects a $1.9 billion reduction in income before taxes which includes a goodwill impairment of $1.6 billion that was not benefited for tax. The 2017 decrease in our income tax benefit reflects a $884.3 million improvement in income before income taxes more than offset by the impact of the 2017 Tax Act, as described more fully below. The effective tax rate was 1.7% in 2018 compared to a negative 305.7% in 2017 and 35.0% in 2016. The 2018, 2017 and 2016 effective tax rates were different than the statutory tax rate due to the 2017 Tax Act (as more fully described below), state income taxes and other discrete tax items which are detailed below. For each of the three years ended December 31, 2018, 2017 and, 2016, current income tax expense relates to state income taxes.

The 2017 Tax Act was signed into law on December 22, 2017. The new law significantly reformed the Internal Revenue Code of 1986, as amended. The reduction in the corporate tax rate required a one-time revaluation of certain tax-related assets and liabilities to reflect their value at the lower corporate tax rate of 21%. We reviewed all of the valuation allowances previously established at the old corporate tax rate of 35% to reflect the appropriate new balances after the enactment of the new law. We recorded a one-time tax benefit related to the tax law change in 2017 of $334.0 million. The following table summarizes our tax activity for each of the last three years (in thousands):

	2018	2017	2016
Total (loss) income before income taxes	$(1,776,970)	$82,120	$(802,138)
U.S. federal statutory rate	21 %	35 %	35 %
Total tax (benefit) expense at statutory rate	(373,164)	28,742	(280,748)
Federal rate change	—	(333,961)	—
State and local income taxes, net of federal benefit	4,427	(604)	(23,514)
State rate and law change	(17,231)	(1,092)	(8,116)
Non-deductible goodwill impairment	344,651	—	—
Non-deductible executive compensation	759	585	1,575
Non-deductible transaction costs	—	—	5,051
Tax less than book equity compensation	2,095	24,843	5,285
Change in valuation allowances:			
Federal valuation allowances & other	20	3,088	2,552
State valuation allowances & other	7,638	27,120	16,874
Permanent differences and other	316	253	291
Total benefit for income taxes	$(30,489)	$(251,026)	$(280,750)
Effective tax rate	1.7 %	(305.7 %)	35.0 %

We estimate our ability to utilize our deferred tax assets by analyzing the reversal patterns of our temporary differences, our loss carryforward periods and the Pennsylvania net operating loss carryforward limitations. Uncertainties such as future commodity prices can affect our calculations and the expiration of loss carryforwards prior to utilization can result in recording a partial as opposed to a full valuation allowance. We expect our effective tax rate to be approximately 24% for 2019, before any discrete tax items. Such estimated rate is based on our current assumptions with respect to, among other things, our earnings, state income tax levels and deductions.

Management's Discussion and Analysis of Financial Condition, Cash Flows, Capital Resources and Liquidity

Cash Flows

The following table presents sources and uses of cash and cash equivalents for each of the last three years (in thousands):

	2018	2017	2016
Sources of cash and cash equivalents			
Operating activities	$990,690	$816,254	$387,068
Disposal of assets	324,549	72,468	193,755
Borrowing on credit facility	2,070,000	2,041,000	2,274,000
MRD Merger, net of cash acquired	—	—	7,180
Other	58,937	110,841	71,530
Total sources of cash and cash equivalents	$3,444,176	$3,040,563	$2,933,533
Uses of cash and cash equivalents			
Additions to natural gas and oil properties	$(960,916)	$(1,148,613)	$(466,252)
Acreage purchases	(60,603)	(58,213)	(43,482)
Other property	(1,477)	(5,710)	(3,052)
Debt repayments	—	(500)	(273,012)
Repayments on credit facility	(2,338,000)	(1,712,000)	(1,487,000)
Repayment of Memorial credit facility	—	—	(597,000)
Dividends paid	(19,940)	(19,840)	(16,682)
Other	(63,143)	(95,553)	(47,210)
Total uses of cash and cash equivalents	$(3,444,079)	$(3,040,429)	$(2,933,690)

Cash flows from operating activities are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operating activities also are impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use available funds to reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our bank credit facility. Because of this, and because our principal source of operating cash flows (proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. We sell a portion of our production at the wellhead under floating market contracts. From time to time, we enter into various derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas, NGLs and oil production. The production we hedge has and will continue to vary from year to year depending on, among other things, our expectation of future commodity prices. Since year-end 2018, we have entered into additional natural gas and NGLs hedges for 2019 and 2020. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. However, production receipts often lag payments to the counterparties. Any interim cash needs are funded by borrowings under the bank credit facility. As of December 31, 2018, we have entered into derivative agreements covering 554.4 Bcfe for 2019 and 32.7 Bcfe for 2020, not including our basis swaps.

Net cash provided from operating activities in 2018 was $990.7 million compared to $816.3 million in 2017 and $387.1 million in 2016. The increase in cash provided from operating activities is a result of a 10% increase in production volumes and a 2% increase in realized prices. Net cash provided from operating activities is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for 2018 was a negative $8.2 million compared to a negative $47.2 million for 2017 and negative $106.4 million in 2016.

Disposal of assets in 2018 includes proceeds of $300.0 million from the sale of a proportionately reduced 1% overriding royalty in our Washington County, Pennsylvania leases and $23.3 million of proceeds from the sale of certain properties in Northern Oklahoma. In 2017, proceeds include $30.8 million from the sale of properties in Western Oklahoma and $40.4 million of proceeds from the sale of properties in the Texas Panhandle. In 2016, proceeds of $78.6 million were received from the sale of various Western Oklahoma properties and $111.5 million of proceeds received from the sale of our non-operated interest in certain wells and gathering facilities in Northeast Pennsylvania.

Additions to natural gas and oil properties are our most significant use of cash and cash equivalents. These cash outlays are associated with our drilling and completion capital budget program. In September 2016, we completed the MRD Merger which added natural gas and oil properties in North Louisiana. The following table shows capital expenditures by region and reconciles to additions to natural gas and oil properties as presented on our consolidated statement of cash flows for each of the last three years (in thousands):

	2018	2017	2016
Appalachian	$715,690	$736,799	$469,082
North Louisiana	131,188	465,820	62,348
Other	(561)	4,225	7,639
Total	846,317	1,206,844	539,069
Change in capital expenditure accrual for proved properties	114,599	(58,231)	(72,817)
Additions to natural gas and oil properties	$960,916	$1,148,613	$466,252

Debt repayments in 2016 includes amounts paid to purchase some of the Memorial senior notes assumed in the MRD Merger.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operating activities, a bank credit facility with uncommitted and committed availability, asset sales and access to the debt and equity capital markets. In April 2018, we entered into an amended and restated bank credit facility with a maturity date of April 13, 2023. We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this primarily through successful drilling programs which require substantial capital expenditures. Lower prices for natural gas, NGLs and oil may reduce the amount of natural gas, NGLs and oil we can economically produce and can also affect the amount of cash flow available for capital expenditures and our ability to borrow or raise additional capital.

We currently believe that net cash generated from operating activities, unused committed borrowing capacity under our bank credit facility and proceeds from asset sales combined with our natural gas, NGLs and oil derivatives currently in place will be adequate to satisfy near-term financial obligations and liquidity needs. While our expectation is to operate within our internally generated cash flow, to the extent our capital requirements exceed our internally generated cash flow and proceeds from asset sales, debt or equity may be issued to fund these requirements. Long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the natural gas and oil business. We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our 2019 capital budget is $756.0 million. Actual capital expenditure levels may vary due to many factors, including drilling results, natural gas, NGLs, crude oil and condensate prices, industry conditions, the prices and availability of goods and services, the extent to which properties are acquired or non-strategic assets sold.

Commodity prices have remained volatile but have improved during 2018 compared to fourth quarter 2017. We have adjusted and must continue to adjust our business through efficiencies and cost reductions to compete in the current price environment which also requires reductions in overall debt levels over time. We plan to continue to work towards profitable growth within cash flows. We would expect to monitor the market and look for opportunities to refinance or reduce debt based on market conditions. We believe we are well-positioned to manage the challenges presented in a low commodity price environment and that we can endure continued volatility in current and future commodity prices by:

- exercising discipline in our capital program with the expectation of funding our capital expenditures with operating cash flow and, if required, with borrowings under our bank credit facility;

- continuing to optimize our drilling, completion and operational efficiencies; and
- continuing to manage price risk by hedging our production volumes.

We believe that we will have adequate capital resources and liquidity for the foreseeable future because (1) we have significant borrowing capacity under our bank credit facility with a maturity of 2023 (2) we have commodity derivatives in place which cover a portion of our 2019 and 2020 production (3) we can reduce our capital expenditures for extended periods of time if necessary and (4) the maturity of our senior and senior subordinated notes extend two years or more and such notes carry attractive fixed interest rates ranging from 4.875% to 5.875%.

Credit Arrangements

Long-term debt at December 31, 2018 totaled $3.8 billion, including $943.0 million of bank credit facility debt, $2.9 billion of senior notes and $49.0 million of senior subordinated notes. As of December 31, 2018, we maintain a bank credit facility with a borrowing base of $3.0 billion and aggregate lender commitments of $2.0 billion. As of December 31, 2018, we also have $281.4 million of undrawn letters of credit. The bank credit facility is secured by substantially all of our assets and has a maturity date of April 13, 2023. Availability under the bank credit facility, during a non-investment grade period, is subject to a borrowing base set by the lenders annually (at their discretion) with an option to reset the borrowing base more often in certain circumstances. Availability under the bank credit facility during an investment grade period is limited to the aggregate lender commitments. The borrowing base is dependent on a number of factors, but primarily the lenders' assessments of future cash flows. Redeterminations of the borrowing base to maintain or reduce the amount thereof require approval of two-thirds of the lenders; increases require 95% approval.

Our bank credit facility imposes limitations on the payment of dividends and other restricted payments (as defined under the debt agreements for our bank debt). The debt agreements also contain customary covenants relating to debt incurrence, liens, investments and financial ratios. We were in compliance with all covenants at December 31, 2018.

Proved Reserves

To maintain and grow production and cash flow, we must continue to develop existing proved reserves and locate or acquire new natural gas, NGLs and oil reserves. The following is a discussion of proved reserves, reserve additions and revisions and future net cash flows from proved reserves.

	Year End December 31,		
	2018	2017	2016
		(Mmcfe)	
Proved Reserves:			
Beginning of year	15,262,361	12,072,322	9,891,663
Reserve additions	3,143,898	3,487,519	1,394,134
Reserve revisions	731,735	506,919	255,794
Purchases	—	10,116	1,259,806
Sales	(262,180)	(81,133)	(164,655)
Production	(803,408)	(733,382)	(564,420)
End of year	18,072,406	15,262,361	12,072,322
Proved Developed Reserves:			
Beginning of year	8,348,074	6,769,908	5,422,075
End of year	9,756,870	8,348,074	6,769,908

Our proved reserves at year-end 2018 were 18.1 Tcfe compared to 15.3 Tcfe at year-end 2017 and 12.1 Tcfe at year-end 2016. Natural gas comprised approximately 67% of our proved reserves year-end 2018 compared to 67% at year-end 2017 and 65% at year-end 2016.

Reserve Additions and Revisions. During 2018, we added 3.1 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 72% of 2018 reserve additions was attributable to natural gas. Included in 2018 proved reserves is a total of 468.9 Mmbbls of ethane reserves (2,074 Bcfe) in the Marcellus Shale, which represents reserves that match volumes delivered under our existing long-term, extendable contracts. Revisions of previous estimates of 731.7 Bcfe include positive pricing revisions of 11.0 Bcfe, improved recovery for our Marcellus Shale properties of 154.0 Bcfe and positive performance revisions of 945.5 Bcfe somewhat offset by 378.8 Bcfe reserves reclassified to unproved due to drilling plans.

During 2017, we added approximately 3.5 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 82% of 2017 reserve additions was attributable to natural gas. Included in 2017 proved reserves is a total of 360.6 Mmbbls of ethane reserves (1,596 Bcfe) in the Marcellus Shale, which represents reserves that match volumes delivered under our existing long-term, extendable contracts. Revisions of previous estimates of 506.9 Bcfe include positive pricing revisions of 46.3 Bcfe, improved recovery for our Marcellus Shale natural gas properties of 597.0 Bcfe and positive performance revisions of 531.9 Bcfe somewhat offset by 668.3 Bcfe of reserves reclassified to unproved due to drilling plans.

During 2016, we added approximately 1.4 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 86% of 2016 reserve additions was attributable to natural gas. Included in 2016 proved reserves is a total of 308.9 Mmbbls of ethane reserves (1,367 Bcfe) in the Marcellus Shale, which represents reserves that match volumes delivered under our existing long-term, extendable contracts. Revisions of previous estimates of 255.8 Bcfe include negative pricing revisions of 23.1 Bcfe and 268.7 Bcfe of reserves reclassified to unproved due to drilling plans more than offset by improved recovery for our Marcellus Shale natural gas properties of 393.2 Bcfe and positive performance revisions of 154.4 Bcfe.

Purchases. In 2017, we purchased 10.1 Bcfe of reserves in North Louisiana. In 2016, we purchased 1.3 Tcfe of reserves related to the MRD Merger.

Sales. In 2018, we sold 143.6 Bcfe of reserves in Pennsylvania and 118.2 Bcfe of reserves in Oklahoma. In 2017, we sold 74.6 Bcfe of reserves in Western Oklahoma and the Texas Panhandle and 6.6 Bcfe of reserves in Pennsylvania. In 2016, we sold 137.5 Bcfe of reserves related to non-operated properties in Northeast Pennsylvania and 24.3 Bcfe of reserves in Western Oklahoma.

Future Net Cash Flows. At December 31, 2018, the present value (discounted at 10%) of estimated future net cash flows from our proved reserves was $13.2 billion. The present value of our estimated future net cash flows at December 31, 2017 was $8.1 billion. This present value was calculated based on the unweighted average first-day-of-the-month oil and gas prices for the prior twelve months held flat for the life of the reserves, in accordance with SEC rules. At December 31, 2018, the after-tax present value of estimated future net cash flows from our proved reserves was $11.1 billion compared to $7.2 billion at December 31, 2017.

The present value of future net cash flows does not purport to be an estimate of the fair market value of our proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money to the evaluating party and the perceived risks inherent in producing oil and gas.

Capitalization and Dividend Payments

As of December 31, 2018 and 2017, our total debt and capitalization were as follows (in thousands):

	2018	2017
Bank debt	$932,018	$1,208,467
Senior notes	2,856,166	2,851,754
Senior subordinated notes	48,677	48,585
Total debt	3,836,861	4,108,806
Stockholders' equity	4,059,431	5,774,272
Total capitalization	$7,896,292	$9,883,078
Debt to capitalization ratio	48.6 %	41.6 %

The amount of future dividends is subject to declaration by the board of directors and primarily depends on earnings, capital expenditures and various other factors. In 2018, we paid $19.9 million in dividends to our stockholders ($0.02 per share per quarter) compared to $19.8 million in 2017 ($0.02 per share per quarter) and $16.7 million in 2016 ($0.02 per share per quarter).

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, derivative obligations, asset retirement obligations, and transportation, gathering and processing commitments. As of December 31, 2018, we do not have any capital leases or any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. As of December 31, 2018, we had a total of $281.4 million of letters of credit outstanding under our bank credit facility. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2018. In addition to the contractual obligations listed on the table below, our consolidated balance sheet at December 31, 2018 reflects accrued interest payable on our bank debt of $1.7 million, which is payable in first quarter 2019. We expect to make interest payments through the end of each note maturity of $28.6 million per year on our 5.75% senior and senior subordinated notes, $67.4 million per year on our 5.0% senior and senior subordinated notes, $36.6 million per year on our 4.875% senior notes and $19.4 million on our 5.875% senior notes.

The following summarizes our contractual financial obligations at December 31, 2018 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our bank credit facility, additional debt issuances and proceeds from asset sales (in thousands).

	Payment due by period					
	2019	2020	2021	2022 and 2023	Thereafter	Total
Debt:						
Bank debt due 2023 [(a)]	$—	$—	$—	$943,000	$—	$943,000
5.75% senior subordinated notes due 2021	—	—	22,214	—	—	22,214
5.0% senior subordinated notes due 2022	—	—	—	19,054	—	19,054
5.0% senior subordinated notes due 2023	—	—	—	7,712	—	7,712
5.75% senior notes due 2021	—	—	475,952	—	—	475,952
5.00% senior notes due 2022	—	—	—	580,032	—	580,032
5.00% senior notes due 2023	—	—	—	741,531	—	741,531
5.875% senior notes due 2022	—	—	—	329,834	—	329,834
4.875% senior notes due 2025	—	—	—	—	750,000	750,000
Other obligations:						
Operating leases, net	12,793	12,384	10,467	13,853	22,001	71,498
Software licenses and other	5,184	5,094	2,503	20	—	12,801
Transportation and gathering commitments	960,000	905,162	878,205	1,633,135	5,854,692	10,231,194
Asset retirement obligation liability [(b)]	5,485	19	—	—	307,250	312,754
Total contractual obligations [(c)]	$983,462	$922,659	$1,389,341	$ 4,268,171	$6,933,943	$ 14,497,576

[(a)] Due at termination date of our bank credit facility. Interest paid on our bank credit facility would be approximately $38.6 million each year assuming no change in the interest rate or outstanding balance.

[(b)] The ultimate settlement amount and timing cannot be precisely determined in advance. See Note 9 to our consolidated financial statements.

[(c)] This table excludes the liability for the deferred compensation plans since these obligations will be funded with existing plan assets.

In addition to the amounts included in the above table, we have entered into additional agreements which are contingent on certain pipeline modifications and/or construction. The largest agreement has a ten-year term beginning on the satisfaction of these contingencies, which may take place in 2019. Based on this contract, we will have additional gathering obligations for natural gas volumes of 350,000 mcf per day until 2029. We also have an agreement with a five-year term, which is expected to begin in 2020, for additional NGLs transportation of 20,000 bbls per day until March 2025.

Delivery Commitments

We have various volume delivery commitments that are related to our Marcellus Shale and North Louisiana areas. We expect to be able to fulfill our contractual obligations from our own production; however, we may purchase third-party volumes to satisfy our commitments or pay demand fees for commitment shortfalls, should they occur. As of December 31, 2018, our delivery commitments through 2031 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2019	347,935	74,000
2020	292,845	71,492
2021	138,011	55,932
2022	83,535	43,000
2023	2,628	35,000
2024 — 2028	—	35,000
2029 — 2031	—	35,000

In addition to the amounts included in the above table, we have contracted with several pipeline companies through 2035 to deliver ethane production volumes from our Marcellus Shale wells. These agreements and related fees, which are contingent upon pipeline construction and/or modification, are for 3,000 bbls per day starting in 2021 and increasing to 10,000 bbls per day through 2035. In addition, we have agreements in place to deliver natural gas volumes from our Marcellus Shale wells, which are also contingent upon pipeline construction and/or modification, for 215,000 mcf per day starting late 2020, decreasing to 151,000 mcf per day in 2024 and decreasing to 100,000 mcf per day in 2026 through early 2029.

Other

In conjunction with the MRD Merger, we have various midstream service agreements in North Louisiana for gathering, processing and transporting of natural gas and NGLs. Pursuant to the gas processing agreement, we must pay a quarterly deficiency payment based on the firm-commitment fixed fee if the cumulative minimum volume commitment as of the end of a quarter exceeds the sum of (i) the cumulative volumes processed under the processing agreement as of the end of the quarter plus (ii) volumes corresponding to deficiency payments incurred prior to each quarter.

We lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages, or other events could result in significant future costs.

Hedging – Natural Gas, Oil and NGLs Prices

We use commodity-based derivative contracts to help manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives as we typically utilize commodity swaps, swaptions and collars to (1) reduce the effect of price volatility on the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. In addition, we may utilize basis contracts to hedge the differential between NYMEX and those of our physical pricing points or between Mont Belvieu and international propane indexes. For more discussion of our derivative activities, see Management's Discussion of Critical Accounting Estimates – Natural Gas and Oil Derivatives below and Item 7A. Quantitative and Qualitative Disclosures about Market Risk – Commodity Price Risk and Other Commodity Risk. For more information regarding the accounting for our derivatives, see the discussion in Notes 2, 10 and 11 to our consolidated financial statements. While there is a risk that the financial benefit of rising natural gas, NGLs and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are a more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital and better access to bank and other credit markets.

Interest Rates

At December 31, 2018, we had $3.8 billion of debt outstanding. Of this amount, $2.9 billion bears interest at fixed rates averaging 5.2%. Bank debt totaling $943.0 million bears interest at floating rates, which averaged 4.1% at year-end 2018. The 30-day LIBOR rate on December 31, 2018 was 2.5%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2018 would cost us approximately $9.4 million in additional annual interest expense.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resources position. However, as is customary in the natural gas and oil industry, we have various contractual work commitments which are described above under cash contractual obligations.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas, NGLs and oil prices and the costs to produce our reserves. Natural gas, NGLs and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. We expect costs in 2019 to continue to be a function of supply and demand. Natural gas and oil prices have remained depressed but have recently improved. We continue to experience a decline in our cost structure.

Management's Discussion of Critical Accounting Estimates

Our discussion and analysis of our 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 our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end, the reported amounts of revenues and expenses during the year and proved natural gas and oil reserves. Some accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Actual results could differ from the estimates and assumptions used.

Certain accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Natural Gas and Oil Properties

We use the successful efforts method of accounting for natural gas and oil producing activities as opposed to the alternate acceptable full cost method. We believe that net assets and net income are more conservatively measured under the successful efforts method of accounting than under the full cost method, particularly during periods of active exploration. One difference between the successful efforts method of accounting and the full cost method is that under the successful efforts method, all exploratory dry holes and geological and geophysical costs are charged against earnings during the periods they occur; whereas, under the full cost method of accounting, such costs are capitalized as assets, pooled with the costs of successful wells and charged against earnings of future periods as a component of depletion expense. Under the successful efforts method of accounting, successful exploration drilling costs and all development costs are capitalized and these costs are systematically charged to expense using the units of production method based on proved developed natural gas and oil reserves as estimated by our engineers and audited by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Proven property leasehold costs are amortized to expense using the units of production method based on total proved reserves. Properties are assessed for impairment as circumstances warrant (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

Proved reserves are defined by the SEC as those volumes of natural gas, NGLs, condensate and crude oil that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in natural gas, NGLs and oil prices can lead to a decision to start up or shut in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in our depletion rates. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, who reports directly to our President and Chief Executive Officer. For additional discussion, see in Items 1 & 2. Business and Properties – Proved Reserves of this report. To further ensure the reliability of our reserve estimates, we engage independent petroleum consultants to audit our estimates of proved reserves. Estimates prepared by third parties may be higher or lower than those included herein. Independent petroleum consultants audited approximately 94% of our reserves in 2018 compared to 98% in 2017 and 96% in 2016. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%. The reserves included in this report are those reserves estimated by our petroleum engineering staff.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While total depletion expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in the timing of when depletion expense is recognized. Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to lower the rate of depletion expense recognition. Based on proved reserves at December 31, 2018, we estimate that a 1% change in proved reserves would increase or decrease 2019 depletion expense by approximately $5.1 million (based on current production estimates). Estimated reserves are used as the basis for calculating the expected future cash flows from property asset groups, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to natural gas and oil producing activities and reserve quantities in Note 19 to our consolidated financial statements. Changes in the estimated reserves are considered a change in estimate for accounting purposes and are reflected on a prospective basis. It should not be assumed that the standardized measure is the current market value of our estimated proved reserves.

We monitor our long-lived assets recorded in natural gas and oil properties in our consolidated balance sheets to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas, NGLs and oil prices, an estimate of the ultimate amount of recoverable natural gas, NGLs and oil reserves that will be produced from the property asset groups future production, future production costs, future abandonment costs, and future inflation. Many assumptions are inherent, and to some extent, interdependent on one another in our estimate of future cash flows. The use of alternate judgments and assumptions could result in different levels of impairment charges. The need to test a property asset group for impairment can be based on several factors, including a significant reduction in sales prices for natural gas, NGLs and/or oil, unfavorable adjustments to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts or environmental regulations. Our natural gas and oil properties are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets which is the level at which depletion is calculated. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated undiscounted future net cash flows. We estimate prices based upon market-related information including published futures prices. The estimated future level of production, which is based on proved and risk adjusted probable and possible reserves, has assumptions surrounding the future levels of prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of future cash flows. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows using a discount rate similar to that used by market participants) and the carrying value of the asset. We cannot predict whether impairment charges may be required in the future. To the extent prices for natural gas, NGLs and oil decline further, costs increase or we have unfavorable adjustments of reserves, or other reasons, we have certain natural gas and oil properties with a carrying value of $1.5 billion that may require impairment in the future. Our recorded impairment of producing natural gas and oil properties was $22.6 million in 2018 compared to $63.7 million in 2017 and $43.0 million in 2016. In 2018, we increased our interest in certain properties in our shallow legacy oil and natural gas assets in Northwest Pennsylvania for a minimal dollar amount for which the fair value of this group of assets had been previously determined to be zero. We recorded impairment expense of $15.3 million related to these properties. Also, in 2018, impairment of $7.3 million was recorded related to natural gas and oil properties in Northern Oklahoma due to the possibility of a sale of these properties. In 2017, $63.7 million of impairment was recorded related to natural gas and oil properties in Oklahoma and the Texas Panhandle due to the possibility of sale of these properties. In 2016, an impairment of $43.0 million was recorded related to natural gas properties in Oklahoma due to lower prices and the possibility of a sale of these properties. We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome. If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record additional impairments.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leaseholds and allocated probable and possible reserve value resulting from acquisitions. The costs are capitalized and evaluated (at least quarterly) as to recoverability based on changes brought about by economic factors and potential shifts in business strategy employed by management. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Potential impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors. A significant portion of our unproved property is the result of value allocated in the MRD Merger related to probable and possible reserves whose recoverability is evaluated based on management expectations and ability to drill these locations. In certain circumstances, our future plans to develop acreage many accelerate our impairment. We have recorded abandonment and impairment expense related to unproved properties of $515.0 million in 2018 compared to $269.7 million in 2017 and $30.1 million in 2016.

Goodwill

As a result of the MRD Merger acquisition in September 2016, we had goodwill in the amount of $1.6 billion at September 30, 2018, the excess of consideration transferred over the fair value of MRD. Goodwill is not amortized but tested for impairment annually, as of November 1, or more frequently if events or circumstances indicate that impairment may exist. We assess the value of our business under either a qualitative or quantitative approach. Under a qualitative approach, we consider various market factors, including applicable key assumptions listed below. These factors are analyzed to determine if events and circumstances have affected the fair value of our business. If we determine that it is more likely than not that our business is impaired, the quantitative approach is used to assess the asset’s fair value and the amount of the impairment. Under a quantitative approach, the fair value is calculated based on key assumptions listed below. If our carrying value exceeds our fair value calculated using the quantitative approach, an impairment charge is recorded for the difference in fair value and carrying value.

When performing a quantitative impairment assessment, fair value is estimated based on a combination of (i) our market capitalization plus a control premium and (ii) projected discounted cash flows (an income approach). Under the income approach, the fair value is based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, proved reserves, the success of future exploration for, and development of, unproved reserves, discount rates and other variables. Key assumptions used in the discounted cash flow model described above include estimated quantities of crude oil, natural gas and NGLs reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating, administrative and capital costs adjusted for inflation. We discount the resulting future cash flows using a peer company based weighted average cost of capital. The estimated market capitalization method is determined by multiplying our average stock price and outstanding common shares plus a control premium. The control premium reflects the impact on asking price for a controlling interest in a company based on recent transaction premiums of comparable companies. We may also use the guideline transaction method or the guideline public company method to corroborate the estimated fair value. This requires management to make certain judgments including the selection of comparable companies and/or comparable recent company asset transactions, transaction premiums and selected financial metrics.

As of November 1, 2018, we conducted a qualitative goodwill impairment assessment by examining relevant events and circumstances which could have a negative impact on our business, such as: macroeconomic conditions, industry and market conditions, including the downturn in the oil and gas industry, cost factors that could have a negative effect on earnings and cash flows, overall financial performance, dispositions and acquisitions, and other relevant entity-specific events. We identified factors, including commodity prices, our proved reserves evaluation and the market value of our common stock. At that time, our analysis indicated that our fair value was not below our book value. Between November 1, 2018 and December 31, 2018, the market value of our common stock declined significantly. We performed a quantitative impairment assessment as of December 31, 2018. Management utilized the assistance of a third-party valuation expert to determine the value of our reporting unit. The fair value was based on a combination of a market capitalization and an income approach. As a result of this measurement, the fair value of goodwill was zero and goodwill was fully impaired.

Fair Value Estimates

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value, or range of present values, using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and do not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy, while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1-Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2-Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.
- Level 3-Unobservable inputs for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimates of the assumptions market participants would use in determining fair value. Our Level 3 measurements consist of instruments using standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. See Note 11 to the consolidated financial statements for disclosures regarding our fair value measurements. Significant uses of fair value measurements include:

- impairment assessments of long-lived assets;
- allocation of the purchase price paid to acquire businesses as to the assets acquired and liabilities assumed;
- impairment assessments of goodwill; and
- recorded value of derivative instruments.

The need to test long-lived assets and goodwill for impairment can be based on several indicators, including a significant reduction in prices of natural gas, oil, condensate and NGLs, sustained declines in our common stock, unfavorable adjustments to reserves, significant changes in the expected timing of production and other changes to contracts or changes in the regulatory environment in which a property is located.

Natural Gas, NGLs and Oil Derivatives

All derivative instruments are recorded on our consolidated balance sheets as either an asset or a liability measured at its fair value. Fair value measurements for all of our derivatives are based on observable market-based inputs that are corroborated by market data and are discussed in Note 10 to our consolidated financial statements. Additional information about derivatives and their valuation may be found in Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore the surface at the end of natural gas and oil production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation ("ARO"), a corresponding adjustment is made to the natural gas and oil property balance. For example, as we analyze actual plugging and abandonment information, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. During 2018, we increased our existing ARO by $12.0 million or approximately 4% of the ARO balance at December 31, 2017. This was primarily due to an increase in our estimated costs to plug and abandon wells in Pennsylvania. During 2017, we increased our existing ARO by $12.5 million or approximately 5% of the ARO balance at December 31, 2016. This was primarily due to an increase in our estimated costs to plug and abandon certain wells in North Louisiana and Pennsylvania. See Note 9 to the consolidated financial statements for disclosures regarding our asset retirement obligation estimates. In addition, increases in the discounted ARO resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in the accompanying consolidated statements of operations. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates. An estimate of the sensitivity to operating results of other assumptions that had been used in recording these liabilities is not practical because of the number of obligations that must be assessed, the number of underlying assumptions and the wide range of possible assumptions.

Income Taxes

We are subject to income and other taxes in all areas in which we operate. For financial reporting purposes, we provide taxes at rates applicable for the appropriate tax jurisdictions. Estimates of amounts of income tax involve interpretation of complex tax laws, including the 2017 Tax Act.

Our consolidated balance sheets include deferred tax assets. Deferred tax assets arise when expenses are recognized in the financial statements before they are recognized in the tax returns or when income items are recognized in the tax returns before they are recognized in the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Ultimately, realization of a deferred tax asset depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences, loss carryforwards or credits.

In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment and judgment is required in considering the relative weight of negative and positive evidence. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. As a result, we may determine that an additional deferred tax asset valuation allowance should be established.

In assessing facts and circumstances surroundings realizability of our deferred tax assets, we are required to apply judgment to determine the weight of both positive and negative evidence in order to conclude whether the valuation allowance is necessary to net operating loss carryforwards and other deferred tax assets. In determining whether a valuation allowance is required for our deferred tax asset balances, we consider, among other factors, current financial position, results of operations, projected future taxable income, tax planning strategies and new legislation. Significant judgment is involved in this determination as we are required to make assumptions about future commodity prices, projected production, development activities, profitability, of future business strategies and forecasted economics in the oil and gas industry. Additionally, changes in the effective tax rate resulting from changes in tax law and our level of earnings may limit utilization of deferred tax assets and will affect valuation of deferred tax balances in the future. Changes in judgment regarding future realization of deferred tax assets may result in a reversal of all or a portion of the valuation allowance. In the period that determination is made, our net income will benefit from a lower effective tax rate.

We believe our net deferred tax assets, after valuation allowances, will ultimately be realized. During 2018, we increased our valuation allowances against our state net operating loss carryforwards, basis differences and credits from $93.8 million as of December 31, 2017 to $101.4 million as of December 31, 2018. The federal valuation allowances decreased from $31.3 million as of December 31, 2017 to $19.0 million as of December 31, 2018. See Note 6 to our consolidated financial statements for further information concerning our income taxes.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, income or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. Actual costs can differ from estimates for many reasons. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. Although we continue to monitor all contingencies closely, particularly our outstanding litigation, we currently have no material accruals for contingent liabilities. We generally record losses related to these type of contingencies as general and administrative expense in the consolidated statements of operations.

Revenue Recognition

Natural gas, NGLs and oil sales are generally recognized when control of the product is transferred and collectability is reasonably assured. We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of gas produced.

Stock-based Compensation Arrangements

The fair value of performance-based share awards (where the performance condition is based on market conditions) is estimated on the date of grant using a Monte Carlo simulation method. A Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant. The fair value of restricted stock awards and performance-based awards where the performance condition is based on internal performance metrics is determined based on the fair market value of our common stock on the date of grant.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. See Note 12 to our consolidated financial statements for more information.

Accounting Standards Not Yet Adopted

Refer to Note 2 to our consolidated financial statements for a discussion of new accounting pronouncements that may affect us in the future.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas, NGLs and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are U.S. dollar denominated.

Market Risk

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices as the volatility of these prices continues to impact our industry. We expect commodity prices to remain volatile and unpredictable in the future. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. These derivative instruments apply to a varying portion of our production and provide only partial price protection. These arrangements limit the benefit to us of increases in prices but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the derivatives. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price changes related to the underlying commodity transaction. While the use of derivative instruments could materially affect our results of operations in a particular quarter or annual period, we believe that the use of these instruments will not have a material adverse effect on our financial position or liquidity. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American natural gas production. Natural gas and oil prices have been volatile and unpredictable for many years. Natural gas prices affect us more than oil prices because approximately 67% of our December 31, 2018 proved reserves were natural gas. We are also exposed to market risks related to changes in interest rates. These risks did not change materially from December 31, 2017 to December 31, 2018.

Commodity Price Risk

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. At times, certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program may also include collars, which establish a minimum floor price and a predetermined ceiling price. We have also entered into combined natural gas derivative instruments containing a fixed price swap and a sold option to extend or double the volume (which we refer to as a swaption). The swap price is a fixed price determined at the time of the swaption contract. If the option is exercised, the contract will become a swap treated consistently with our fixed-price swaps. At December 31, 2018, our derivatives program includes swaps, swaptions and collars. These contracts expire monthly through December 2020. Their fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2018, approximated a net derivative asset of $80.9 million compared to a net derivative asset of $13.6 million at December 31, 2017. This change is primarily related to the settlements of derivative contracts during 2018 and to the natural gas, NGLs and oil futures prices as of December 31, 2018 in relation to the new commodity derivative contracts we entered into during 2018 for 2019 and 2020. At December 31, 2018, the following commodity derivative contracts were outstanding, excluding our basis swaps which are discussed below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price	Fair Market Value (in thousands)
Natural Gas				
2019	Swaps	1,318,041 Mmbtu/day	$ 2.86	$ 2,502
2019	Swaptions	113,014 Mmbtu/day	$ 2.81 [1]	$ (5,694)
2020	Swaptions	80,000 Mmbtu/day	$ 2.77 [1]	$ 2,922
Crude Oil				
2019	Swaps	7,000 bbls/day	$ 55.26	$ 20,029
2020	Swaps	1,562 bbls/day	$ 61.05	$ 6,452
2019	Collars	1,000 bbls/day	$ 63.00 - $ 73.03	$ 5,945
NGLs (C3-Propane)				
January-June, 2019	Swaps	8,500 bbls/day	$ 0.92/gallon	$ 18,719
January-June, 2019	Collars	3,983 bbls/day	$ 0.92 - $1.02/gallon	$ 8,538
NGLs (NC4-Normal Butane)				
January-March, 2019	Swaps	2,250 bbls/day	$ 1.22/gallon	$ 4,083
NGLs (C5-Natural Gasoline)				
2019	Swaps	2,429 bbls/day	$ 1.44/gallon	$ 17,371

[1] Contains a combined derivative instrument consisting of a fixed price swap and a sold option to extend or double the volume. In 2019, we also have swaps in place for 150,000 Mmbtu per day on which the counterparty can elect to extend the contract through December 2020 at a weighted average price of $2.81. In 2020, if the counterparty elects to double the volume, we would have additional swaps covering 80,000 Mmbtu per day at a weighted average price of $2.77.

In the future, we expect our NGLs production to continue to increase. In our Marcellus Shale operations, propane is a large product component of our NGLs production and we believe NGLs prices are somewhat seasonal. Therefore, the percentage of NGLs prices to NYMEX WTI (or West Texas Intermediate) will vary due to product components, seasonality and geographic supply and demand. We sell NGLs in several regional and international markets.

Currently, the Appalachian region has limited local demand and infrastructure to accommodate ethane. We have previously announced agreements wherein we have contracted to either sell or transport ethane from our Marcellus Shale area, two of which began operations in late 2013. Our Mariner East transportation agreement and our terminal/storage arrangement at Sunoco’s Marcus Hook Industrial Complex facility near Philadelphia began operations in early 2016. If we are not able to sell a portion of our ethane, we may be required to curtail production which will adversely affect our revenues and cash flow. However, as we have done in the past, we also may be able to purchase or divert natural gas to blend with our rich residue gas.

Other Commodity Risk

We are impacted by basis risk as natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the swaps above, we have entered into natural gas basis swap agreements. The price we receive for our natural gas production can be more or less than the NYMEX price because of adjustments for delivery location (“basis”), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively lock in the basis adjustments. The fair value of the natural gas basis swaps, which expire monthly through October 2021, was a net derivative asset of $4.8 million at December 31, 2018 and the volumes are for 70,940,000 Mmbtu.

As of December 31, 2018, we also had propane spread swap contracts which lock in the differential between Mont Belvieu and international propane indices. These contracts settle monthly in January through June and October through December 2019 and the fair value of these contracts was a net derivative asset of $117,000 on December 31, 2018.

In connection with our international propane swaps, at December 31, 2018, we had freight swap contracts which lock in the freight rate for a specific trade route on the Baltic Exchange. These contracts settle monthly through December 2019 and cover 10,000 metric tons per month with a fair value net derivative liability of $561,000 on December 31, 2018.

Commodity Sensitivity Analysis

The following table shows the fair value of our swaps and basis swaps and the hypothetical change in fair value that would result from a 10% and a 25% change in commodity prices at December 31, 2018. We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risks should be mitigated by price changes in the underlying physical commodity (in thousands):

		Hypothetical Change in Fair Value Increase in Commodity Price of		Hypothetical Change in Fair Value Decrease in Commodity Price of	
	Fair Value	10%	25%	10%	25%
Swaps	$ 69,156	$(141,759)	$(353,090)	$142,901	$357,338
Swaptions	(2,772)	(29,398)	(83,682)	23,946	54,365
Collars	14,483	(3,453)	(8,140)	3,544	8,809
Basis swaps	4,883	(51)	(31)	6	15
Freight swaps	(561)	436	1,090	(436)	(1,090)

Counterparty Risk

Our commodity-based contracts expose us to the credit risk of non-performance by the counterparty to the contracts. Our exposure is diversified among major investment grade financial institutions and commodity traders and we have master netting agreements with the majority of our counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At December 31, 2018, our derivative counterparties include twenty financial institutions, of which all but four are secured lenders in our bank credit facility. Counterparty credit risk is considered when determining the fair value of our derivative contracts. While counterparties are major investment grade financial institutions and large commodity traders, the fair value of our derivative contracts have been adjusted to account for the risk of non-performance by certain of our counterparties, which was immaterial. Our propane sales from the Marcus Hook facility near Philadelphia are short-term and are to a single purchaser. Ethane sales from Marcus Hook are to a single international customer bearing a credit rating similar to Range.

Interest Rate Risk

We are exposed to interest rate risk on our bank debt. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest costs, interest rate volatility and financing risk. This is accomplished through a mix of fixed rate publicly traded debt and variable rate bank debt. At December 31, 2018, we had $3.8 billion of debt outstanding. Of this amount, $2.9 billion bears interest at a fixed rate averaging 5.2%. Bank debt totaling $943.0 million bears interest at floating rates, which was 4.1% at December 31, 2018. On December 31, 2018, the 30-day LIBOR rate was 2.5%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2018 would cost us approximately $9.4 million in additional annual interest expense.

The fair value of our senior and subordinated debt is based on year-end December 2018 quoted market prices. The following table presents information on these fair values (in thousands):

	Carrying Value	Fair Value
Fixed rate debt:		
Senior Subordinated Notes due 2021 (The interest rate is fixed at a rate of 5.75%)	$22,214	$21,638
Senior Subordinated Notes due 2022 (The interest rate is fixed at a rate of 5.00%)	19,054	17,072
Senior Subordinated Notes due 2023 (The interest rate is fixed at a rate of 5.00%)	7,712	6,690
Senior Notes due 2021 (The interest rate is fixed at a rate of 5.75%)	475,952	455,972
Senior Notes due 2022 (The interest rate is fixed at a rate of 5.00%)	580,032	519,343
Senior Notes due 2022 (The interest rate is fixed at a rate of 5.875%)	329,834	306,571
Senior Notes due 2023 (The interest rate is fixed at a rate of 5.00%)	741,531	654,683
Senior Notes due 2025 (The interest rate is fixed at a rate of 4.875%)	750,000	616,313
	$2,926,329	$2,598,282

Item 8. financial statements and supplementary data

RANGE RESOURCES CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control over Financial Reporting

To the Stockholders of Range Resources Corporation:

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance regarding the preparation and fair presentation of published financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. 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.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2018. In making this assessment, which was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on our assessment, we believe that, as of December 31, 2018, our internal control over financial reporting is effective based on those criteria.

Ernst and Young LLP, the independent registered public accounting firm that audited our financial statements included in this annual report, has issued an attestation report on our internal control over financial reporting as of December 31, 2018. This report appears on the following page.

By:	/s/ JEFFREY L. VENTURA	By:	/s/ Mark S. scucchi
	Jeffrey L. Ventura		Mark S. Scucchi
	Chief Executive Officer and President		Senior Vice President and Chief Financial Officer

Fort Worth, Texas

February 25, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Range Resources Corporation

Opinion on Internal Control over Financial Reporting

We have audited Range Resources Corporation's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Range Resources Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of Range Resources Corporation as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive (loss) income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and our report dated February 25, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible 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 an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ Ernst & Young LLP

Fort Worth, Texas

February 25, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Range Resources Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive (loss) income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at 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 U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 25, 2019 expressed an unqualified opinion thereon.

Adoption of ASU No. 2014-09

As discussed in Note 3 to the consolidated financial statements, the Company changed its method of accounting for revenue in 2018 due to the adoption of Accounting Standards Update (ASU) No. 2014-09 Revenue from Contracts with Customers (Topic 606) and the related amendments.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company’s auditor since 2003.

Fort Worth, Texas

February 25, 2019

RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31, 2018	2017
Assets		
Current assets:		
Cash and cash equivalents	$545	$448
Accounts receivable, less allowance for doubtful accounts of $6,118 and $7,111	490,723	348,833
Derivative assets	87,953	58,607
Inventory and other	22,964	21,346
Total current assets	602,185	429,234
Derivative assets	4,842	273
Goodwill	—	1,641,197
Natural gas and oil properties, successful efforts method	13,085,206	13,216,453
Accumulated depletion and depreciation	(4,062,021)	(3,649,716)
	9,023,185	9,566,737
Other property and equipment	111,908	114,361
Accumulated depreciation and amortization	(102,132)	(99,695)
	9,776	14,666
Other assets	68,166	76,734
Total assets	$9,708,154	$11,728,841
Liabilities		
Current liabilities:		
Accounts payable	$227,344	$343,871
Asset retirement obligations	5,485	6,327
Accrued liabilities	475,848	317,531
Accrued interest	41,990	43,511
Derivative liabilities	4,144	44,233
Total current liabilities	754,811	755,473
Bank debt	932,018	1,208,467
Senior notes	2,856,166	2,851,754
Senior subordinated notes	48,677	48,585
Deferred tax liabilities	666,668	693,356
Derivative liabilities	3,462	9,789
Deferred compensation liabilities	67,542	101,102
Asset retirement obligations and other liabilities	319,379	286,043
Total liabilities	5,648,723	5,954,569
Commitments and contingencies		
Stockholders' Equity		
Preferred stock, $1 par 10,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.01 par 475,000,000 shares authorized, 249,519,687 issued		

at December 31, 2018 and 248,144,397 issued at December 31, 2017	2,495	2,481
Common stock held in treasury, 9,665 shares at December 31, 2018 and 14,967 shares at December 31, 2017	(391)	(599)
Additional paid-in capital	5,628,447	5,577,732
Accumulated other comprehensive loss	(658)	(1,332)
Retained (deficit) earnings	(1,570,462)	195,990
Total stockholders' equity	4,059,431	5,774,272
Total liabilities and stockholders' equity	$9,708,154	$11,728,841

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

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF operations

(In thousands, except per share data)

	Year Ended December 31,		
	2018	2017	2016
Revenues and other income:			
Natural gas, NGLs and oil sales	$2,851,077	$2,176,287	$1,197,215
Derivative fair value (loss) income	(51,192)	213,350	(261,391)
Brokered natural gas, marketing and other	482,760	221,393	164,115
Total revenues and other income	3,282,645	2,611,030	1,099,939
Costs and expenses:			
Direct operating	139,531	134,252	97,388
Transportation, gathering, processing and compression	1,117,816	761,183	565,209
Production and ad valorem taxes	46,149	42,882	25,443
Brokered natural gas and marketing	496,047	220,311	168,576
Exploration	34,117	53,662	32,325
Abandonment and impairment of unproved properties	514,994	269,725	30,076
General and administrative	209,812	233,406	184,772
MRD Merger expenses	—	—	37,225
Termination costs	(373)	3,770	(519)
Deferred compensation plan	(18,631)	(50,915)	19,153
Interest	210,209	195,679	168,213
Depletion, depreciation and amortization	635,467	624,992	524,102
Impairment of proved properties	22,614	63,679	43,040
Impairment of goodwill	1,641,197	—	—
Loss (gain) on the sale of assets	10,666	(23,716)	7,074
Total costs and expenses	5,059,615	2,528,910	1,902,077
(Loss) income before income taxes	(1,776,970)	82,120	(802,138)
Income tax (benefit) expense:			
Current	—	17	98
Deferred	(30,489)	(251,043)	(280,848)
	(30,489)	(251,026)	(280,750)
Net (loss) income	$(1,746,481)	$333,146	$(521,388)
Net (loss) income per common share:			
Basic	$(7.10)	$1.34	$(2.75)
Diluted	$(7.10)	$1.34	$(2.75)

Weighted average common shares outstanding:			
Basic	246,171	245,091	189,868
Diluted	246,171	245,458	189,868

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

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

(In thousands)

	Year Ended December 31,		
	2018	2017	2016
Net (loss) income	$(1,746,481)	$333,146	$(521,388)
Other comprehensive loss:			
Postretirement benefits:			
Actuarial gain	526	—	—
Prior service cost	—	(1,769)	—
Amortization of prior service costs	369	—	—
Income tax (expense) benefit	(221)	437	—
Total comprehensive (loss) income	$(1,745,807)	$331,814	$(521,388)

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

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2018	2017	2016
Operating activities:			
Net (loss) income	$(1,746,481)	$333,146	$(521,388)
Adjustments to reconcile net (loss) income to net cash provided from operating activities:			
Deferred income tax benefit	(30,489)	(251,043)	(280,848)
Depletion, depreciation and amortization and impairment of proved properties	658,081	688,671	567,142