RANGE RESOURCES CORP
Form 10-K
February 25, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark one)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

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 x 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 x

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 x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (check one):

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2015 was $8,138,124,000. 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, 2016, there were 169,585,625 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 2016 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 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 and its ownership interests in equity method investments. 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 Item 15 of this report.

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PART II

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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1 and 2. Business and Properties, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and Item 7A. Quantitative Disclosures about Market Risk, includes 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 statements typically contain words such as "may," "anticipate," "believe," "estimate," "expect," "intend," "plan," "predict," "target," "project," "should," "would" or similar words, indicating that future 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 management believes 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 "Item 1A. Risk Factors."

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

- natural gas, crude oil and natural gas liquids ("NGLs") prices;
- 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 or sustained low commodity prices;
- ability to develop existing reserves or acquire new reserves;
- changes in political or economic conditions in our key operating markets;
- prices and availability of goods and services;
- unforeseen hazards such as weather conditions, acts of war or terrorist acts;
- electronic, cyber or physical security breaches;
- 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 Item 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.

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, mostly focused in the Appalachian region of the United States. Our corporate offices are located at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 (telephone (817) 870-2601). We have a regional office in Canonsburg, Pennsylvania. Our common stock is listed and trades on the New York Stock Exchange (the "NYSE") under the symbol "RRC." At December 31, 2015, we had 169.4 million shares outstanding.

Our 2015 production had the following characteristics:

- average total production of 1,395.4 Mmcfe per day, an increase of 20% from 2014;
- 71% natural gas;
- total natural gas production of 362.7 Bcf, an increase of 26% from 2014;
- total NGLs production of 20.4 Mmbbls (including ethane), an increase of 8% from 2014;
- total crude oil and condensate production of 4.1 Mmbbls which was the same as 2014; and
- 86% of our total production was from the Marcellus Shale in Pennsylvania.

At year-end 2015, our proved reserves had the following characteristics:

- 9.9 Tcfe of proved reserves;
- 64% natural gas, 33% NGLs and 3% crude oil;
- 55% proved developed;
- 98% operated;
- 97% of proved reserves are in the Marcellus Shale in Pennsylvania;
- a reserve life index of approximately 19 years (based on fourth quarter 2015 production);
- a pretax present value of $3.0 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 $2.7 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 discounted estimated future income tax of $303.3 million at December 31, 2015.

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 Governance Guidelines, the charters of the Audit Committee, the Compensation Committee, the Dividend Committee, and 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 public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, 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 consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our business objective is to increase reserves and production through internally generated drilling projects coupled with occasional complementary acquisitions and divestitures of non-core assets. 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;
- maintain a multi-year drilling inventory;
- focus on cost efficiency;
- maintain a long-life reserve base;
- 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.

Commit to Environmental Protection and Worker and Community Safety. We strive to implement the latest technologies and best commercial practices to minimize 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 participate in FracFocus, a national publically accessible web-based registry to report, on a well-by-well basis, the additives and chemicals and amount of water used in the hydraulic fracturing process for each of the wells we operate. 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 one region: Pennsylvania. Concentrating our drilling and producing activities in a core area allows us to develop the regional expertise needed to interpret specific geological and operating conditions and develop economies of scale. Operating in a core area as large as the Marcellus Shale allows us to reach our goal of consistent production and reserve growth at attractive returns. We intend to further develop our acreage in the Marcellus Shale 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.

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 5,000 proven and unproven drilling locations in inventory. We actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential.

Focus on Cost Efficiency. We concentrate in areas which we believe to have sizeable hydrocarbon deposits in place that will allow us to consistently increase 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 Long-Life Reserve Base. 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. We use our drilling, divestiture and acquisition activities to assist in executing this strategy.

Market Our Products to A Large Number of Customers in Different Markets Under a Variety of Commercial Terms. We market our natural gas, NGLs, and oil 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 this in maintaining a strong balance sheet, ample liquidity and using commodity derivatives to help stabilize our realized prices. We believe 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, 2015, our employees and directors owned equity securities in our benefit plans (vested and unvested) that had an aggregate market value of approximately $114 million.

Significant Accomplishments in 2015

Production growth – In 2015, our production averaged 1,395.4 Mmcfe per day, an increase of 20% from 2014. Drilling in the Marcellus Shale play in Pennsylvania drove our production growth. Our capital program is designed to allocate investments based on growth projects that produce the highest returns.

Proved reserves – Total proved reserves decreased 4% in 2015, from 10.3 Tcfe to 9.9 Tcfe. On a pro forma basis, adjusted for the sale of our Virginia and West Virginia assets, our proved reserves increased 6% in 2015, despite a reduced capital budget in 2015. This achievement is the result of continued drilling success, as all of our production and reserve growth in 2015, before asset sales, came from our drilling program. 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.

Low price environment initiatives – As a result of the significant drop in commodity prices, we took action to reduce capital spending, operating costs and general and administrative costs. We lowered our 2015 capital expenditure budget that was announced in December 2014 from $1.3 billion to $870 million. Other initiatives included the closing of our Oklahoma City divisional office in early 2015 and additional workforce reductions, which has continued into early 2016. In February 2016, the board of directors approved a reduction of our quarterly dividend from $0.04 per share to $0.02 per share.

Successful drilling program – In 2015, we drilled 152 gross natural gas and oil wells. We replaced 248% of our production through drilling in 2015 and our overall drilling success rate was 100%. We continue to build our drilling inventory which is critical to our ability to drill a large number of wells each year on a cost effective and efficient basis.

Large resource potential – Maintaining an exposure to large potential resources is important. We continued expansion of our shale plays in 2015. We have three large unconventional and prospective plays – the Marcellus, Utica/Point Pleasant and Upper Devonian shales in Pennsylvania. These plays cover expansive areas, provide multi-year drilling opportunities, are in many cases stacked pay and, collectively, have sustainable lower risk growth profiles. The economics of these plays have been enhanced by continued advancements in drilling and completion technologies.

Focus on financial flexibility – We ended 2015 with less debt than year-end 2014. Debt per mcfe of proved reserves was $0.27 at December 31, 2015 compared to $0.30 at December 31, 2014. In May 2015, we issued $750.0 million principal amount of 4.875% senior notes due 2025 and in July 2015, we redeemed all $500.0 million aggregate principal amount of our 6.75% senior subordinated notes due 2020. As of December 31, 2015, we maintain a $4.0

billion bank credit facility, with a borrowing base of $3.0 billion and committed borrowing capacity was $2.0 billion. 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.

Dispositions completed – In December 2015, we sold the majority of our Virginia and West Virginia assets for proceeds of $876.0 million, before closing adjustments. We recognized a pretax loss of $407.7 million. We also received $14.9 million of additional proceeds during the year related to the sale of miscellaneous proved and unproved property and inventory.

Leasing acquisitions completed – In 2015, we leased or renewed $73.0 million of acreage located in our core areas, primarily in the Marcellus Shale. We continue to see outstanding results in the Marcellus Shale. Production in the Marcellus Shale increased 27% and we continue to prove up acreage, acquire additional acreage and gain access to additional pipeline and processing capacity.

Continued development of processing, pipeline takeaway capacity and marketing of NGLs – We continue our efforts to ensure we have sufficient processing capacity and marketing agreements in place for our Pennsylvania production. 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 ("Mariner East"). At the end of December 2014, line fill on the propane portion of this pipeline was completed with propane delivered to storage caverns to be sold at a later date. At the end of January 2016, startup of ethane operations was in process. We expect both propane and ethane operations on Mariner East to be fully functional by the end of first quarter 2016.

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 extremely 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.

Natural gas prices are primarily determined by North American supply and demand. The New York Mercantile Exchange ("NYMEX") monthly settlement prices for natural gas averaged $2.65 per mcf in 2015, with a high of $3.19 per mcf in January and a low of $2.03 per mcf in November. In 2014, monthly NYMEX settlement prices averaged $4.37 per mcf. Since the end of 2015, natural gas prices have remained depressed, with the monthly settlement price for natural gas falling from $2.21 per mcf in December 2015 to $2.19 per mcf in February 2016. Natural gas prices continue to be under pressure largely due to excess supply of natural gas caused by the high productivity of shale plays in the United States which is outpacing demand. Demand for drilling rigs, oilfield supplies and drill pipe declines with falling commodity prices but such declines tend to lag behind the declines in natural gas and crude oil prices. Depressed natural gas prices continue to reflect the expectation there will be an oversupply of natural gas in 2016 and storage levels will remain higher than normal.

Significant factors that will impact 2016 crude oil prices include worldwide economic conditions, political and economic developments in the Middle East, 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 $49.21 per barrel in 2015, with a high of $59.83 per barrel in June and a low of $37.33 per barrel in December. In 2014, NYMEX monthly settlement oil averaged $92.64 per barrel. Since the end of 2015, crude oil prices have declined significantly, with the monthly settlement price for crude oil falling from $37.33 per barrel in December 2015 to $31.78 per barrel in January 2016. The market oversupply of oil is expected to continue in 2016 with oil prices expected to remain under pressure.

NGLs prices are generally determined by North American supply and demand. We expect NGLs prices in 2016 to continue to be under pressure due to excess supply. The growth of unconventional drilling has substantially increased the supply of NGLs, which has caused a significant decline in NGL component prices. While more export facilities have been built and NGL exports are increasing along with the expansion of ethane cracking capacity, the overall United States demand for NGL products has not kept pace with supply of such products.

Natural gas, NGLs and oil prices affect:

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

Natural gas and NGLs prices are likely to affect us more than oil prices because approximately 97% of our proved reserves is natural gas and NGLs. Any 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 and oil 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 operations are limited to the United States and we are currently focused on both unconventional resource plays and conventional plays in Pennsylvania.

Outlook for 2016

For 2016, we have established a $495.0 million capital budget for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. Of this amount, 98% is allocated to our Marcellus Shale operations. 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. To the extent our 2016 capital requirements exceed our internally generated cash flow, proceeds from asset sales, drawing on our committed capacity under our bank credit facility, debt or equity 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 2016 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions. As a result of the significant drop in commodity prices, we have implemented initiatives to reduce capital spending, operating costs and administrative expenses to minimize spending in excess of cash flows. During 2015 and continuing into early 2016, we continue to work with our service providers to reduce costs. Also during 2015 and continuing into early 2016, we have implemented workforce reduction plans to reduce general operating expenses and we expect to continue to achieve savings from these initiatives into 2016. In February 2016, the board of directors approved a reduction of our quarterly dividend from $0.04 per share to $0.02 per share.

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. For more information, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	Year Ended December 31,		
	2015	2014	2013
Production			
Natural gas (Mmcf)	362,687	286,926	264,528
Natural gas liquids (Mbbls)	20,356	18,821	9,255
Crude oil and condensate (Mbbls)	4,084	4,070	3,827
Total (Mmcfe) [a]	509,328	424,267	343,022
Average sales prices (excluding derivative settlements)			
Natural gas (per mcf)	$2.13	$3.98	$3.61
Natural gas liquids (per bbl)	8.67	23.60	34.07
Crude oil and condensate (per bbl)	34.28	77.80	86.00
Total (per mcfe) [a]	2.14	4.48	4.66
Average realized prices (including derivatives settlements that qualified for hedge accounting):			
Natural gas (per mcf)	$2.13	$3.99	$4.03
Natural gas liquids (per bbl)	8.67	23.60	34.07
Crude oil and condensate (per bbl)	34.28	79.16	87.47
Total (per mcfe) [a]	2.14	4.51	5.00
Average realized prices (including all derivatives settlements):			
Natural gas (per mcf)	$3.07	$3.79	$4.00

Natural gas liquids (per bbl)	10.73	24.31	32.71
Crude oil and condensate (per bbl)	71.28	79.75	84.70
Total (per mcfe) [(a)]	3.18	4.41	4.91
Average realized prices (including all derivative settlements and third party transportation costs)			
Natural gas (per mcf)	$2.12	$2.80	$3.08
Natural gas liquids (per bbl)	8.12	22.04	31.29
Crude oil and condensate (per bbl)	71.28	79.75	84.70
Total (per mcfe) [(a)]	2.41	3.64	4.16
Direct operating costs			
Lease operating (per mcfe) [(a)]	$0.25	$0.31	$0.34
Workovers (per mcfe) [(a)]	0.01	0.03	0.02
Stock-based compensation (per mcfe) [(a)]	0.01	0.01	0.01
Total (per mcfe) [(a)]	$0.27	$0.35	$0.37

(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 of oil and natural gas prices.

Proved Reserves

The following table sets forth our estimated proved reserves for years ended 2015, 2014 and 2013 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]	%
2015:					
Proved Developed	3,376,165	309,306	31,679	5,422,075	55 %
Undeveloped	2,901,533	239,828	21,514	4,469,588	45 %
Total Proved	6,277,698	549,134	53,193	9,891,663	100 %
2014:					
Proved Developed	3,583,051	270,271	24,180	5,349,761	52 %
Undeveloped	3,339,785	245,636	24,478	4,960,468	48 %
Total Proved	6,922,836	515,907	48,658	10,310,229	100 %
2013:					
Proved Developed	2,797,483	206,477	26,054	4,192,666	51 %
Undeveloped	2,868,162	167,935	22,306	4,009,608	49 %
Total Proved	5,665,645	374,412	48,360	8,202,274	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 of oil and natural gas prices.

The following table sets forth summary information by area with respect to estimated proved reserves at December 31, 2015:

	Reserve Volumes					PV-10 [a]	
	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe)	%	Amount (In thousands)	%
Appalachian Region	6,103,703	536,117	46,026	9,596,563	97 %	$2,899,549	96 %
Other	173,995	13,017	7,167	295,100	3 %	129,657	4 %
Total	6,277,698	549,134	53,193	9,891,663	100 %	$3,029,206	100 %

(a) PV-10 was prepared using the twelve-month average prices for 2015, 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 $2.7 billion at December 31, 2015. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of $303.3 million at December 31, 2015. Included in the $3.0 billion pretax PV-10 is $2.4 billion related to proved developed reserves.

Reserve Estimation

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. We also had Wright and Company, Inc., an independent petroleum consultant, conduct an audit of our year-end reserves. This engineering firm was selected for their geographic expertise and their historical experience in engineering certain properties. The proved reserve audits performed for 2015, 2014 and 2013, in the aggregate represented 94%, 96% and 96% of our proved reserves. The reserve audits performed for 2015, 2014 and 2013, in the aggregate represented 97%, 98% and 97% of our 2015, 2014 and 2013 associated pretax present value of proved reserves discounted at ten percent. Copies of the summary reserve report prepared by our independent petroleum consultant is included as an exhibit to this Annual Report on Form 10-K. The technical person at our 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 consultant 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 consultant 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 consultant 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 consultant performs 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 auditor. When such differences do not exceed 10% in the aggregate, our reserve auditor is 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 Chairman, 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, 2015 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, natural gas liquids 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, well logs, geologic maps and available downhole and production data, seismic data, well test data and reservoir simulation modeling.

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, 2015, NGLs represented approximately 33% of our total proved reserves on an mcf equivalent basis. NGLs are products priced by the gallon (and sold by the barrel) to the end-user. In reporting proved reserves and production of NGLs, we have included production and reserves in barrels. Prices for a barrel of NGLs in 2015 averaged approximately 75% lower than the average prices 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, 2015, we have 292.8 Mmbbls of ethane reserves (1,296 Bcfe) associated with our Marcellus Shale properties, which are included in NGLs proved reserves and represent 53% of our total NGLs reserves. We currently include ethane in our proved reserves which match volumes delivered under our existing long-term, extendable ethane contracts.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2015, our PUDs totaled 21.5 Mmbbls of crude oil, 239.8 Mmbbls of NGLs and 2.9 Tcfe of natural gas, for a total of 4.5 Tcfe. Costs incurred in 2015 relating to the development of PUDs were approximately $398.8 million. Approximately 98% of our PUDs at year-end 2015 were associated with the Marcellus Shale. All PUD drilling locations are scheduled to be drilled prior to the end of 2020 with more than 78% of the future development costs expected to be spent in the next three years. Changes in PUDs that occurred during the year were due to:

- conversion of approximately 762.9 Bcfe of PUDs into proved developed reserves;
- addition of new PUDs consisting of 915.7 Bcfe;

441.9 Bcfe negative revision with 1.2 Tcfe of reserves reclassified to unproved because of reduced future capital spending due to lower commodity prices partially offset by improved recovery and other positive performance revisions of 725.6 Bcfe; and
201.8 Bcfe reduction from the sale of properties.

For an additional description of changes in PUDs for 2015, see Note 18 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):

	2015	2014	2013	2012	2011
Future net cash flows	$8,666	$26,993	$21,029	$11,156	$15,610
Present value:					
Before income tax	3,029	10,070	7,898	3,960	6,084
After income tax (Standardized Measure)	2,726	7,593	5,862	3,224	4,515
Benchmark prices (NYMEX):					
Gas price (per mcf)	2.59	4.35	3.67	2.76	4.12
Oil price (per bbl)	50.13	94.42	97.33	95.05	95.61
Wellhead prices:					
Gas price (per mcf)	2.07	4.14	3.75	2.75	3.55
Oil price (per bbl)	35.07	79.04	86.66	86.91	85.59
NGLs price (per bbl)	11.74	27.20	25.93	32.23	49.24

Future net cash flows represent projected revenues from the sale of proved reserves, net of production and development costs (including 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 region of the United States, primarily in the Marcellus Shale in Pennsylvania. 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, 2015.

Region	Average Daily Production (mcfe per day)	Production (Mmcfe)	Percentage of Production		Proved Reserves (Mmcfe)	Percentage of Proved Reserves	
Appalachian	1,329,409	485,234	95	%	9,596,562	97	%
Other	66,010	24,094	5	%	295,101	3	%
Total	1,395,419	509,328	100	%	9,891,663	100	%

The following table summarizes our costs incurred for the year ended December 31, 2015 (in thousands):

Region	Acreage Purchases	Development Costs	Exploration Costs	Gathering Facilities	Asset Retirement Obligations	Total
Appalachian	$ 72,029	$ 686,434	$ 107,246	$ 12,559	$ 20,678	$898,946
Other	996	21,834	1,665	778	1,506	26,779
Total costs incurred	$ 73,025	$ 708,268	$ 108,911	$ 13,337	$ 22,184	$925,725

Approximately 97% of our proved reserves at December 31, 2015 are located in the Marcellus Shale in our Appalachian region. This play has a large portfolio of drilling opportunities. The following table below sets forth annual production volumes, average sales prices and production cost data for our wells in the Marcellus Shale which, as of December 31, 2015, is our only field in which reserves are greater than 15% of our total proved reserves.

	Marcellus Shale		
	2015	2014	2013
Production:			
Natural gas (Mmcf)	301,721	224,034	203,926
NGLs (Mbbls)	19,389	17,093	7,213
Crude oil and condensate (Mbbls)	3,387	3,089	2,529
Total Mmcfe [(a)]	438,377	345,127	262,377
Sales Prices: [(b)]			
Natural gas (per mcf)	$ 0.94	$ 2.72	$2.59
NGLs (per bbl)	5.66	20.32	33.19
Crude oil and condensate (per bbl)	31.78	73.77	82.11
Total (per mcfe)	1.14	3.43	3.72
Production Costs:			
Lease operating (per mcfe)	$0.16	$0.19	$0.16
Production and ad valorem tax (per mcfe) [(c)]	0.05	0.08	0.11

(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 of 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/Point Pleasant, Medina and Upper Devonian formations which principally produce at depths ranging from 3,500 feet to 11,500 feet. We own 4,462 net producing wells, 99% of which we operate. Our average working interest in this region is 87%. As of December 31, 2015, we have approximately 1.0 million gross (905,000 net) acres under lease.

Reserves at December 31, 2015 were 9.6 Tcfe, a decrease of 298.1 Bcfe, or 3%, from 2014. Drilling additions (1.2 Tcfe), favorable reserve revisions for performance and improved recovery were more than offset by production, downward revisions for proved undeveloped reserves no longer in our current five year development plan (1.1 Tcfe), sales of 948.3 Bcfe and negative pricing revisions. Annual production increased 25% from 2014. During 2015, we spent $793.7 million in this region to drill 123 (113.4 net) development wells and 19 (19.0 net) exploratory wells, all of which were productive. At December 31, 2015, the Appalachian region had an inventory of over 350 proven drilling locations and over 80 proven recompletions. During the year, the Appalachian region drilled 84 proven locations, added 85 new proven drilling locations and deleted 152 proven drilling locations with reserves reclassified to unproved because of 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 seven years. We had over 350 proven drilling locations at December 31, 2015. Our 2015 production from the Marcellus Shale increased 27% from 2014. During 2015, we drilled 111 (101.4 net) development wells and 19 (19.0 net) exploratory wells, all of which were successful. In 2016, we plan to drill over 65 net wells. During 2015, we had approximately 9 drilling rigs in the field and expect to run an average of 3 rigs throughout 2016.

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 liquid fractionation. In 2011, we executed an ethane sales contract for the liquids-rich gas in southwestern Pennsylvania whereby a third party will purchase and transport ethane from the tailgate of a third-party processing and fractionation facilities to the international border for further delivery into Canada. Initial deliveries commenced in second half 2013. Also in 2011, we entered into an agreement to transport ethane to the Gulf Coast where initial deliveries also commenced in late 2013.

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. Line fill on the propane portion of this pipeline was completed in late December 2014, with propane delivered to storage caverns to be sold at a later date. At the end of January 2016, startup of ethane operations was in process. We expect both propane and ethane operations to be fully functional by the end of first quarter 2016. In the meantime, since 2012, we have been transporting a portion of our propane by rail and truck to the 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 the same terminal near Philadelphia which is expected to begin in early 2016.

Other

Our other operations include drilling, production and field operations in the Texas Panhandle, as well as in the Anadarko Basin of western Oklahoma, the Nemaha Uplift of Northern Oklahoma and Kansas, the Permian Basin of West Texas and Mississippi. We own 444 net producing wells in these locations, 96% of which we operate. Our average working interest is 74%. As of December 31, 2015, we have approximately 396,000 gross (308,000 net) acres under lease.

Total proved reserves decreased 120.5 Bcfe, or 29%, at December 31, 2015, when compared to year-end 2014. Drilling additions (31.5 Bcfe) were offset by production, property sales (15.1 Bcfe), negative performance revisions and downward revisions for proved undeveloped reserves no longer in our current five year development plan (61.7 Bcfe) and negative pricing revisions. Annual production volumes decreased 36% from 2014. During 2015, this region spent $23.5 million to drill 10 (8.9 net) development wells, all of which were productive. During the year, the region achieved a 100% drilling success rate.

At December 31, 2015, this area had a development inventory of over 55 proven drilling locations and over 30 proven recompletions. During the year, this area drilled 4 proven locations, added 12 new proven locations and deleted 41 proven drilling locations. Development projects include recompletions and infill drilling. These activities also include increasing reserves and production through cost control, upgrading lifting equipment, improving gathering systems and surface facilities, and performing restimulations and refracturing operations.

Divestitures

Over the last three years, we have divested over $1.4 billion 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 through reduced debt levels. In 2015, we sold the following assets:

Virginia and West Virginia. On December 30, 2015, we closed the sale of the majority of our natural gas and oil properties and gathering assets in Virginia and West Virginia for cash proceeds of $876.0 million, before closing adjustments. We used the proceeds from this sale to reduce the balance on our bank credit facility.

West Texas. In February 2015, we sold our remaining properties in West Texas for proceeds of $10.5 million.

Miscellaneous. During the year ended December 31, 2015, we sold miscellaneous unproved property, inventory and other assets for proceeds of $4.4 million.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2015. 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	5,628	4,801	93%
Crude oil	113	105	85%
Total	5,741	4,906	85%

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. As of December 31, 2015, we were in the process of drilling 30 (28.0 net) wells.

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	133.0	122.3	228.0	215.7	178.0	171.9
Dry	¾	¾	1.0	1.0	1.0	1.0
Exploratory wells						
Productive	19.0	19.0	25.0	21.4	39.0	35.5
Dry	¾	¾	1.0	1.0	1.0	0.2
Total wells						
Productive	152.0	141.3	253.0	237.1	217.0	207.4
Dry	¾	¾	2.0	2.0	2.0	1.2
Total	152.0	141.3	255.0	239.1	219.0	208.6
Success ratio	100 %	100 %	99.2 %	99.2 %	99.1 %	99.4 %

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, 2015. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Illinois	¾	¾	13,161	7,294	13,161	7,294
Kansas	¾	¾	25,242	24,804	25,242	24,804
Mississippi	5,192	3,140	904	623	6,096	3,763
Oklahoma	110,361	104,638	195,072	140,429	305,433	245,067
Pennsylvania	719,118	653,127	285,160	245,148	1,004,278	898,275
Texas	25,830	17,168	19,582	9,635	45,412	26,803
West Virginia	6,160	4,597	2,959	2,221	9,119	6,818
	866,661	782,670	542,080	430,154	1,408,741	1,212,824
Average working interest		90 %		79%		86 %

Undeveloped Acreage Expirations

The table below summarizes by year our undeveloped acreage scheduled to expire in the next five years.

	Acres		% of Total
As of December 31,	Gross	Net	Undeveloped
2016	111,030	104,327	24%
2017	146,894	103,053	24%
2018	50,000	38,963	9%
2019	36,296	31,468	7%
2020	16,292	14,606	3%

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 to five years. However, we have in the past 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 from time to time and expect to allow additional acreage to expire in the future.

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 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, 2016, we had 744 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.

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. Our ability to replace and expand our reserve base depends on our ability to attract and retain quality personnel and identify and acquire suitable producing properties and prospects for future drilling. 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 natural gas processors or users of NGLs. 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 and tanks to purchaser-specified delivery points. These expenses vary based on volume, distance shipped and the fee charged by the third-party gatherers and transporters. In Oklahoma and Texas, our production is transported primarily through purchaser-owned or third-party trucks, field gathering systems and transmission pipelines. 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.

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 three ethane agreements to sell or transport ethane from our Marcellus Shale area. Initial deliveries commenced in late 2013 on two of these agreements. The remaining agreement is expected to begin 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 depends 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 summer months and increases during the winter 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.

Governmental Regulation

Enterprises that sell securities in public markets are subject to regulatory oversight by federal agencies such as the SEC and the NYSE, a private stock exchange which 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. An overview of these 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, tribal 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 and production;
- 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 of up to $1,000,000 per day per violation. 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, defined and described below. It therefore 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 can result in substantial penalties. 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, 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 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 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.

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 drilling 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.

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 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.

We currently own or lease, and have in the past owned or leased, properties that for many years have been used 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 (UIC) 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 lawmaker's proposed new legislation that would, among other things, require injection wells be located more than 2,000 feet from any occupied dwelling. Should future 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 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. Also, in March 2015, 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. 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 and Texas 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 State of New York. 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 is 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 and also could 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. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA issued a draft report in June 2015 concluding that, although hydraulic fracturing activities have the potential 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. The EPA did not find evidence that these mechanisms have led to widespread, systematic impacts on drinking water resources. The draft report has not yet been finalized. These existing or any future studies, depending on any meaningful further results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking 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 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, as amended, 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 President Obama's Strategy to Reduce Methane Emissions, the EPA proposed in August 2015 new regulations that will set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. The EPA is expected to finalize the proposed regulations in 2016. In a second example, in October 2015, the EPA finalized a rulemaking proposal that revises the National

Ambient Air Quality Standard for ozone to 70 parts per billion for both the 8-hour primary and secondary standards. Compliance with one or both of these 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.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the U.S., 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 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. For example, as noted above, the EPA has proposed new regulations that will set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. 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. 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 Federal Bureau of Land Management (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, governmental permits or authorizations that are subject to the requirements of NEPA are required. 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, 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, 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”) is 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. In March 2014, the FWS announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements. The designation of previously unprotected species in areas where we operate as threatened or endangered 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 our reserves.

The Migratory Bird Treaty Act 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.

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 2015, nor do we anticipate that such expenditures will be material in 2016. However, we regularly have 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.

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, which may adversely affect our business, financial condition or results of operations. 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 2012 and 2015, the average NYMEX monthly settlement price of natural gas has been as high as $5.56 per mcf and as low as $2.03 per mcf. During that same time frame, the average NYMEX monthly oil settlement price was as high as $106.54 per barrel and as low as $37.33 per barrel. Over the past few months, natural gas and oil prices have continued to be depressed with the average NYMEX monthly settlement price for natural gas for February 2016 falling to $2.19 per mcf and the monthly settlement for crude oil falling to $31.78 per barrel in January 2016. Likewise, 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 63% of our December 31, 2015 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 natural gas, NGLs and oil;
- the price, availability and demand for alternative fuels and sources of energy;
- weather conditions;
- the level of consumer demand for natural gas, NGLs and oil;
- 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 facilities;
- the effect of worldwide energy conservation efforts;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree and maintain oil price and production controls;
- potential U.S. exports of oil, NGLs and/or liquefied natural gas;
- political conditions in natural gas and oil producing regions; and
- domestic (federal, state and local) and foreign governmental regulations and taxes.

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 each May and for event driven unscheduled redeterminations.

Producing natural gas, NGLs and oil may involve unprofitable efforts. As of December 31, 2015, the relationship between the price of oil and the price of natural gas continues to be at a wide spread. Normally, 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 NGLs and condensate. However, 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 $1.17 per gallon and as low as $0.34 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 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 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 writedowns of our proved natural gas and oil properties. In the past we have been required to write down the carrying value of certain of our natural gas and oil properties, and there is a risk that we will be required to take additional writedowns in the future. Recent commodity price declines have resulted in an impairment of our proved oil and gas properties. For example, in third quarter 2015, we recorded a $502.2 million impairment of natural gas and oil properties in Northern Oklahoma and our legacy producing assets in Northwest Pennsylvania and, in fourth quarter 2015, we recorded additional impairment of $87.9 million primarily related to our natural gas and oil properties in the Texas Panhandle. These impairments were due to a significant decline in commodity prices in 2015. 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 and reduces our reported earnings and increases our leverage ratios. If commodity prices remain depressed, we may be required to further impair the carrying value of our natural gas and oil properties.

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. During 2015, natural gas, NGLs and oil prices declined significantly. 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;
facility or equipment malfunctions;
equipment failures or accidents;
title problems;
pipe or cement failures;
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; and
uncontrollable flows of oil, natural gas or well fluids.

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 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 growth 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. 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.

Our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in one geographic area. Our producing properties are geographically concentrated in the Appalachian Basin in Pennsylvania. At December 31, 2015, 97% 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, 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 will 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 are 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.

Our senior subordinated notes, which were issued pursuant to an indenture, include a limitation on the amount of credit facility debt we can incur. Certain thresholds, as set forth in the Indenture debt incurrence test, may limit our ability to incur debt under our bank credit facility in excess of a $1.5 billion floor amount based on the levels of commodity prices for natural gas, NGLs and crude oil used in the annual calculation of discounted future net cash flows relating to proved oil and gas reserves. Given this indenture provision and based on the year-end 2015 discounted future net cash flows, our bank credit facility usage is limited to $1.5 billion until higher prices or proved reserve additions increase discounted future net cash flows.

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, 2015, approximately 96% of our debt is at fixed interest rates with the remaining 4% 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 capital 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 previously and created substantial volatility and uncertainty, and could do so again, with the related negative impact on global economic activity and the financial markets. 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. In addition, it may also cause our commodity derivative arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, negative economic conditions could lead to reduced demand for natural gas, NGLs and oil or lower prices for natural gas 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.

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 and 2. Business and Properties – Competition.”

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 even may 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 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. While there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years, there has been a number of regulatory initiatives to address GHG emissions. 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, pursuant to President Obama’s Strategy to Reduce Methane Emissions, the EPA proposed in August 2015 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. These actions 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 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 and 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.

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, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC, the courts or 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 pipelines rates and rules and policies that may affect rights of access to transportation capacity. For more information regarding the regulation of our operations, see "Items 1 and 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 to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. 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 and 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, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation. Legislation previously has been 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 the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. As of December 31, 2015, we had a tax basis of $2.2 billion related to prior years capitalized intangible drilling costs, which will be amortized over the next five years.

The passage of this 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, and any such change could negatively affect our financial condition and results of operations.

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. In addition, a recent court case in Pennsylvania has challenged the state's authority to impose a limit on the utilization of net operating loss carryforwards at the greater of $5 million or 30 percent of apportioned Pennsylvania taxable income. We will be monitoring the appeals process of this case and its impact on our ability to utilize our Pennsylvania net operating loss carryforwards.

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 March 2015, the BLM released a final rule setting forth disclosure requirements and other regulatory mandates for hydraulic fracturing on federal lands.

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 and Texas, 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, as Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. 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, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing and the EPA is receiving public commentary on its study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. These studies and initiatives, or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing.

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. 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, all of which could have an adverse effect on our operations and financial condition.

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. As these new position limit rules are not yet final, the impact of those provisions 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 also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. 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 the ESA, the Migratory Bird Treaty Act, 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 is required to consider listing numerous species as endangered or threatened under the ESA before completion of the agency's 2017 fiscal year. The 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. 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 and 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.

Currently, there is little demand for ethane in the Appalachian region and insufficient facilities to supply the existing demand elsewhere. We have announced three ethane agreements wherein we have contracted to either sell or transport ethane from our Marcellus Shale area. We cannot assure you that all these facilities will become or will remain available.

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. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is performed.

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 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.

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 certain liabilities for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, 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 have limited control over the activities on properties we do not operate. Other companies operate some of the properties in which we have an interest. We do not operate approximately 2% of our wells, as of December 31, 2015. We have limited ability to influence or control the operation or future development of non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a materially adverse effect on the realization of our targeted returns on capital in drilling or acquisitions activities and lead to unexpected future costs.

We exist in a litigious environment. Certain parties may be able to bring suit regarding our existing or planned operations or allege a violation of an existing contract. Any such action could delay when planned operations can actually commence or could cause a halt to existing production until such alleged violations are resolved by the courts. Not only could we incur significant legal and support expenses in defending our rights, but halting existing production or delaying planned operations could impact our future operations and financial condition. Such legal disputes could also 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.

The potential for such security threats has 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, 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 remedial actions, loss of business or potential liability.

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

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 and oil prices generally stimulate demand for ancillary services. Similarly, lower natural gas 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 quickly 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 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. In 2005, 2006, 2007 and 2008, we sold 52.7 million shares of common stock to finance acquisitions or pay down our outstanding bank credit facility. In 2009 and 2010, we issued 1.1 million shares of common stock to purchase acreage in the Marcellus Shale. In 2014, we issued approximately 4.6 million shares of common stock in a public stock offering with the proceeds used to redeem our 8% senior subordinated notes due 2019. Our ability to repurchase securities for cash is limited by our bank credit facility and our senior subordinated note agreements. We also issue restricted stock and performance share units (and previously stock appreciation rights and stock options) 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. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Dividend limitations. Limits on the payment of dividends and other restricted payments, as defined, are imposed under our bank credit facility and under our senior subordinated note agreements. 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, 2013 to December 31, 2015, the price of our common stock reported by the New York Stock Exchange ranged from a low of $20.79 per share to a high of $95.41 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.

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 2015, trading volume averaged approximately 4.0 million shares per day. The following table shows the quarterly high and low sale prices and cash dividends declared as reported on the NYSE composite tape for the past two years.

	High	Low	Cash Dividends Declared
2014:			
First quarter	$90.76	$79.28	$ 0.04
Second quarter	95.41	82.63	0.04
Third quarter	87.37	66.98	0.04
Fourth quarter	74.64	51.83	0.04
2015:			
First quarter	$55.74	$43.88	$ 0.04
Second quarter	65.53	48.46	0.04
Third quarter	49.40	30.33	0.04
Fourth quarter	37.73	20.79	0.04

Between January 1, 2016 and February 22, 2016, the common stock traded at prices between $31.94 and $19.21 per share. Our senior subordinated notes and our senior notes are not listed on an exchange, but trade over-the-counter.

Holders of Record

On February 22, 2016, there were approximately1,087 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 $0.04 per common share for each of the four quarters of 2015, 2014 and 2013. The bank credit facility and our senior subordinated notes allow 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 our level of earnings and capital expenditures and other matters that the board deems relevant. Dividends on Range common stock are limited to our legally available funds. In February 2016, our board of directors reduced the quarterly dividend from $0.04 per share to $0.02 per share. For more information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

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 Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for the five years ended December 31, 2015. The graph assumes that $100 was invested in the Company's common stock and each index on December 31, 2010, and that dividends were reinvested.

	2010	2011	2012	2013	2014	2015
Range Resources Corporation	$100	$138	$140	$188	$120	$55
S&P 500 Index	100	102	118	157	178	181
DJ U.S. Expl. & Prod. Index	100	96	101	134	119	91

*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.

ITEM 6. SELECTED FINANCIAL DATA AND PROVED RESERVE DATA

The following table shows selected financial information for the five years ended December 31, 2015. Prior year total assets, bank debt and senior subordinated notes reflect the retrospective reclassification that is discussed in Note 2 to our consolidated financial statements for debt issuance costs and deferred taxes. Significant producing property dispositions may affect the comparability of year-to-year financial and operating data. 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. In the first half of 2013, we sold certain Delaware and Permian Basin properties in Southeast New Mexico and West Texas for proceeds of $275.0 million. In the first half of 2011, we sold our Barnett Shale properties for proceeds of $889.3 million, including certain derivative contracts assumed by the buyer and these operations are reflected as discontinued operations. 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,				
	2015	2014	2013	2012	2011
Statements of Operations Data:					
Natural gas, NGLs and oil sales	$1,089,644	$1,911,989	$1,715,676	$1,351,694	$1,173,266
Total revenues and other income	1,598,068	2,426,057	1,770,428	1,408,572	1,228,383
Total costs and expenses	2,650,430	1,395,172	1,620,849	1,383,516	1,150,120
(Loss) income from continuing operations	(713,685)	634,382	115,722	13,002	42,706
Discontinued operations, net of taxes	¾	¾	¾	—	15,320
Net (loss) income	(713,685)	634,382	115,722	13,002	58,026
(Loss) income from continuing operations per share:					
–Basic	$(4.29)	$3.81	$0.71	$0.08	$0.26
–Diluted	(4.29)	3.79	0.70	0.08	0.26
Net (loss) income per share:					
–Basic	(4.29)	3.81	0.71	0.08	0.36
–Diluted	(4.29)	3.79	0.70	0.08	0.36
Costs per mcfe: (a)					
Direct operating expense	$0.27	$0.35	$0.37	$0.42	$0.60
Production and ad valorem tax expense	0.07	0.11	0.13	0.24	0.15
General and administrative expense	0.38	0.50	0.85	0.63	0.80
Interest expense	0.33	0.40	0.51	0.61	0.66
Depletion, depreciation and amortization expense	1.14	1.30	1.44	1.62	1.80
	$2.19	$2.66	$3.30	$3.52	$4.01
Average Daily Production:					
Natural gas (mcf)	993,662	786,099	724,735	591,679	397,825
NGLs (bbls)	55,770	51,563	25,356	19,036	14,664
Oil (bbls)	11,189	11,150	10,486	7,790	5,369
Total mcfe (b)	1,395,419	1,162,374	939,786	752,637	518,019
Balance Sheet Data:					
Current assets (c)	$439,074	$570,292	$196,887	$327,614	$315,263
Current liabilities (d)	351,720	639,677	495,561	417,219	455,337

Natural gas and oil properties, net	6,361,305	7,977,573	6,758,437	6,096,184	5,157,566
Total assets	6,900,031	8,704,604	7,203,127	6,685,604	5,806,080
Bank debt	86,427	713,221	495,683	730,982	176,482
Senior notes	738,101	¾	¾	¾	¾
Senior subordinated notes	1,826,775	2,317,603	2,600,288	2,104,072	1,759,095
Stockholders' equity[e]	2,759,658	3,457,429	2,414,452	2,357,392	2,392,420
Weighted average diluted shares outstanding	166,389	164,403	161,407	160,307	159,441
Cash dividends declared per common share	0.16	0.16	0.16	0.16	0.16
Statements of Cash Flows Data:					
Net cash provided from operating activities	$683,700	$954,135	$743,538	$647,099	$631,637
Net cash used in investing activities	(218,772)	(1,245,456)	(983,436)	(1,528,558)	(547,981)
Net cash (used in) provided from financing activities	(464,905)	291,421	239,994	881,619	(86,412)
Proved Reserves Data (at end of period):					
Natural gas (Bcf)	6,278	6,923	5,666	4,793	4,010
NGLs (Mmbbls)	549	516	374	240	142
Oil and condensate (Mmbbls)	53	49	48	45	31
Total proved reserves (Bcfe)	9,892	10,310	8,202	6,506	5,054

(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 of oil and natural gas prices.

(c) 2015 includes $281.5 million of derivative assets compared to $363.0 million in 2014, $4.4 million in 2013, $137.6 million in 2012 and $173.9 million in 2011.

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(d) 2015 includes $1.1 million of derivative liabilities. 2013 includes $26.2 million of derivative liabilities.
(e) Stockholders' equity includes other comprehensive income of $6.2 million in 2013 compared to $83.9 million in 2012 and $156.6 million in 2011. There was no other comprehensive income in either 2015 or 2014.

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 "Disclosures Regarding Forward-Looking Statements" immediately prior to Part I and Item 1A. Risk Factors.

Overview of Our Business

We are an independent natural gas, natural gas liquids ("NGLs") and oil company engaged in the exploration, development and acquisition of natural gas and crude oil properties located primarily in the Appalachian region 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 consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our business objective is to increase reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions. 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. Natural gas and crude oil prices continue to be depressed. 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 and oil fluctuate widely and affect:

- revenues, profitability and cash flow;
- the quantity of natural gas, NGLs and oil that we can economically produce;
- 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, 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. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. One type of agreement is a netback agreement, under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the price we receive from the purchaser. In the case of NGLs, we generally receive a net price from the purchaser (which is net of processing costs) and is also recorded as revenue at the net price we receive from the purchaser. Under the other type of agreement, we sell natural gas or oil at a specific delivery point, pay transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In that case, we record transportation costs we pay to third parties as transportation, gathering and compression expense. Also included in natural gas, NGLs and oil sales revenues and derivative fair value income or loss are the effects of derivative accounting. Derivatives included in natural gas, NGLs and oil sales reflect settlements on those derivatives that qualify for hedge accounting. Cash settlements of derivative contracts that are not accounted for as hedges are included in derivative fair value income or loss in the accompanying statements of operations. Effective March 1, 2013, we elected to de-designate all commodity contracts that were previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. For more information, see Note 10 to our consolidated financial statements. Brokered natural gas, marketing and other revenues include revenue we receive as a result of selling natural gas that is not related to our production (brokered), revenue from the release of transportation capacity where we have taken capacity ahead of our production, marketing fees we receive from third parties and transportation revenue we receive from gathering lines we own.

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 and compression. Under some of our sales arrangements, we sell natural gas and NGLs at a specific delivery point, pay transportation, gathering and compression costs to a third party and receive proceeds from the purchaser with no deduction. Transportation, gathering 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. Ad valorem taxes are generally based on reserve values at the end of each year. 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 related to 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 granted 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 and expenses associated with oil and gas lease expirations.

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 restricted stock, performance share units (“PSUs”) and stock appreciation rights (“SARS”) 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.

Interest expense. We typically finance a portion of our cash requirements with borrowings under our bank credit facility and with longer-term debt securities. Also, included here are also 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, substantially all of our federal taxes are deferred. As of December 31, 2015, we have $84.0 million of valuation allowances on the portion of our state net loss carryforwards for Louisiana, Mississippi, Oklahoma, Pennsylvania and West Virginia and our federal net loss carryforwards which we do not believe are realizable. In addition, we have a valuation allowance of $3.1 million on the deferred tax asset related to our deferred compensation plans. 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 and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.”

Management’s Discussion and Analysis of Results of Operations

Natural gas, NGLs and oil prices remained depressed in 2015. Nevertheless, we had many operational, financial and strategic successes in 2015.

Overview of 2015 Results

During 2015, we achieved the following financial and operating results:

- achieved 20% annual production growth;
- achieved 6% annual proved reserve growth; excluding the impact of the sale of our Virginia and West Virginia assets;
- drilled 141 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 direct operating expenses per mcfe 23% from 2014;
- reduced general and administrative expenses per mcfe 24% from 2014;
- reduced interest expense per mcfe 18% from 2014;
- reduced our DD&A rate per mcfe 12% from 2014;
- continued to focus on financial flexibility by redeeming all $500.0 million of 6.75% senior subordinated notes due in 2020 and issued $750.0 million aggregate principal amount of 4.875% senior notes due 2025;
- achieved a debt per mcfe of proved reserves of $0.27 compared to $0.30 in 2014;
- entered into additional commodity-based derivative contracts for 2016;
- received $876.0 million of proceeds, before closing adjustments, from the sale of our Virginia and West Virginia producing properties and $14.9 million of proceeds from the sale of miscellaneous non-core oil and gas assets;
- reduced debt which strengthened our balance sheet;
- realized $683.7 million of cash flow from operating activities; and
- ended the year with stockholders’ equity of $2.8 billion.

Operationally, our 2015 performance reflects another year of successfully executing our strategy of growth through drilling. Our success enabled us to increase proved reserves by 6%, excluding the impact of the sale of our Virginia and West Virginia assets during the year. As evidenced by history and our current industry environment, the prices at which we sell our production are volatile and we have no control over them. Therefore, to improve our profitability, we focus our efforts on improving operating efficiency. 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.

Acquisitions

During 2015, we spent $73.0 million to acquire unproved acreage compared to $226.5 million in 2014 and $137.5 million in 2013. We continue selective acreage leasing and lease renewals to add to our acreage positions primarily in the Marcellus Shale play in Pennsylvania. See additional information below regarding our 2014 exchange of natural gas and oil properties in West Texas for properties, cash and other assets in Virginia which we refer to as the Conger Exchange.

Divestitures

Virginia and West Virginia. In December 2015, we sold the majority of our producing properties and gathering assets in Virginia and West Virginia for cash proceeds of $876.0 million, before closing adjustments. We closed the transaction at the end of December 2015 and recognized a pretax loss of $407.7 million related to this sale.

Texas. In February 2015, we sold our remaining West Texas properties for cash proceeds of $10.5 million and we recognized a loss of $101,000.

In December 2013, we announced our plan to offer for sale certain of our properties in the Permian Basin. These properties included approximately 73,000 net acres, almost all of which are held by production in Glasscock and Sterling Counties, Texas. In April 2014, we entered into an exchange agreement with EQT Corporation and certain of its affiliates (collectively, "EQT") in which we sold these assets in exchange for producing properties, (including approximately 138,000 net acres) and other EQT assets in Virginia and $145.0 million in cash, before closing adjustments (the "Conger Exchange"). We closed the exchange transaction in June 2014 and we recognized a pretax gain of $282.7 million related to this exchange. In fourth quarter 2014, we also sold miscellaneous proved properties in East Texas for proceeds of $5.0 million and recognized a gain of $467,000.

In April 2013, we sold certain of our Permian and Delaware Basin properties in West Texas and Southeast New Mexico for a price of $275.0 million. We closed this disposition in April 2013 and we recorded a pretax gain of $79.1 million. During 2013, we sold miscellaneous unproved and proved property for proceeds of $33.5 million and we recorded a gain of $8.8 million.

Oklahoma. In December 2014, we sold certain oil and gas properties in Western Oklahoma for proceeds of $2.6 million with no gain or loss recognized.

Pennsylvania. In June 2015, we sold miscellaneous unproved properties for proceeds of $3.4 million and we recognized a loss of $2.9 million. In December 2014, we sold miscellaneous unproved properties for proceeds of $18.8 million and we recognized a gain of $617,000. In September 2013, we sold our equity method investment in a drilling company for proceeds of $7.0 million and recognized a gain of $4.4 million.

2016 Outlook

For 2016, the board of directors approved a $495.0 million capital budget for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. 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. To the extent our 2016 capital requirements exceed our internally generated cash flow, proceeds from asset sales, drawing on our committed capacity under our bank credit facility, debt or equity may be issued 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 2016 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions. We expect natural gas prices to remain depressed in 2016 which reflects the current state of over-supply and higher than normal storage levels. As a result of the significant drop in commodity prices, we have implemented initiatives to reduce capital spending, operating costs and administrative expenses to minimize spending in excess of cash flows. During 2015 and continuing into early 2016, we continue to work with our service providers to reduce costs. Also during 2015 and continuing into early 2016, we have implemented workforce reduction plans to reduce general operating expenses and we expect to continue to achieve savings from these initiatives into 2016.

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. Natural gas and crude oil prices have remained depressed with the average NYMEX monthly settlement price for natural gas falling to $2.19 per mcf for February 2016 and crude oil falling to $31.78 per barrel in January 2016. The following table lists average NYMEX prices for natural gas and oil and the Mont Belvieu NGL composite price for the years ended December 31, 2015, 2014 and 2013.

	Year Ended December 31,		
	2015	2014	2013
Average NYMEX prices [a]			
Natural gas (per mcf)	$2.65	$4.37	$3.67
Oil (per bbl)	$49.21	$92.64	$98.20
Mont Belvieu NGL composite (per gallon)	$0.40	$0.76	$0.78

[a] Based on average of bid week prompt month prices.

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 "Source of Our Revenues" above. In 2015, natural gas, NGLs and oil sales decreased 43% from 2014 with a 20% increase in production more than offset by a 53% decrease in realized prices. In 2014, natural gas, NGLs and oil sales increased 11% from 2013 with a 24% increase in production partially offset by a 10% decrease in realized prices. In 2013, we discontinued hedge accounting. See Note 10 to our consolidated financial statements for additional information. 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):

	2015	2014	2013
Natural gas, NGLs and Oil sales			
Gas wellhead	$773,093	$1,140,989	$954,673
Gas hedges realized	¾	4,686	110,948
Total gas revenue	$773,093	$1,145,675	$1,065,621
Total NGLs revenue	$176,546	$444,152	$315,272
Oil and condensate wellhead	$140,005	$316,625	$329,182
Oil hedges realized	¾	5,537	5,601
Total oil and condensate revenue	$140,005	$322,162	$334,783
Combined wellhead	$1,089,644	$1,901,766	$1,599,127
Combined hedges	¾	10,223	116,549
Total natural gas, NGLs and oil sales	$1,089,644	$1,911,989	$1,715,676

Our production continues to grow through drilling success as we place new wells on production partially offset by the natural decline of our natural gas and oil reserves through production and asset sales. For 2015, our production volumes increased 25% in our Appalachian region when compared to 2014. For 2014, our production volumes increased 30% in our Appalachian region when compared to 2013. Our production for each of the last three years is set forth in the following table:

	2015	2014	2013
Production [(a)]			
Natural gas (mcf)	362,686,707	286,926,099	264,528,254
NGLs (bbls)	20,356,110	18,820,526	9,254,801
Crude oil and condensate (bbls)	4,084,069	4,069,568	3,827,491
Total (mcfe) [(b)]	509,327,781	424,266,663	343,022,006
Average daily production [(a)]			
Natural gas (mcf)	993,662	786,099	724,735
NGLs (bbls)	55,770	51,563	25,356
Crude oil and condensate (bbls)	11,189	11,150	10,486
Total (mcfe) [(b)]	1,395,419	1,162,374	939,786

[(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 of oil and natural gas prices.

Our average realized price (including all derivative settlements and third-party transportation costs paid by Range) received during 2015 was $2.41 per mcfe compared to $3.64 per mcfe in 2014 and $4.16 per mcfe in 2013. Because we record transportation costs on two separate bases, as required by generally accepted accounting principles, we believe computed final realized prices should include the impact of transportation, gathering 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. Our average realized price (including all derivative settlements and third-party transportation costs paid by Range) calculation also includes all cash settlements for derivatives, whether or not they qualify for hedge accounting. Average realized price calculations for each of the last three years are shown below:

	2015	2014	2013
Average Prices			
Average sales prices (excluding derivatives settlements):			
Natural gas (per mcf)	$2.13	$3.98	$3.61
NGLs (per bbl)	8.67	23.60	34.07
Crude oil (per bbl)	34.28	77.80	86.00
Total (per mcfe) [(a)]	2.14	4.48	4.66
Average realized prices (including derivative settlements that qualified for hedge accounting):			
Natural gas (per mcf)	$2.13	$3.99	$4.03
NGLs (per bbl)	8.67	23.60	34.07
Crude oil (per bbl)	34.28	79.16	87.47
Total (per mcfe) [(a)]	2.14	4.51	5.00
Average realized prices (including all derivative settlements):			
Natural gas (per mcf)	$3.07	$3.79	$4.00
NGLs (per bbl)	10.73	24.31	32.71
Crude oil (per bbl)	71.28	79.75	84.70
Total (per mcfe) [(a)]	3.18	4.41	4.91
Average realized prices (including all derivative settlements and third party transportation costs paid by Range):			
Natural gas (per mcf)	$2.12	$2.80	$3.08
NGLs (per bbl)	8.12	22.04	31.29
Crude oil (per bbl)	71.28	79.75	84.70
Total (per mcfe) [(a)]	2.41	3.64	4.16

[(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 of oil and natural gas prices.

Transportation, gathering and compression expense was $396.7 million in 2015 compared to $325.3 million in 2014 and $256.2 million in 2013. 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 and transportation agreements. The year ended December 31, 2014 also includes the impact of an ethane transportation contract which commenced initial deliveries in late 2013. We have included these costs in the calculation of average realized prices (including all derivative settlements and third party transportation expenses paid by Range).

Derivative fair value income (loss) was income of $416.4 million in 2015 compared to an income of $383.5 million in 2014 and a loss of $61.8 million in 2013. Through February 28, 2013, some of our derivatives did not qualify for hedge accounting and were accounted for using the mark-to-market accounting method whereby all realized and unrealized gains or losses related to these contracts were included in derivative fair value income or loss in our consolidated statement of operations. Effective March 1, 2013, we prospectively discontinued hedge accounting for those contracts that qualified for hedge accounting. Since March 1, 2013, 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, 2015, our commodity derivative contracts were recorded at their fair value, which was a net pretax asset of $283.3 million, a decrease of $118.4 million from the $401.7 million net pretax asset recorded as of December 31, 2014. 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 as a pretax gain of $5.5 million as of December 31, 2015 compared to a pretax gain of $1.7 million as of December 31, 2014. As of December 31, 2015, we also have propane basis swaps to limit the volatility caused by changing differentials between Mont Belvieu and international propane indexes which is recognized as a pretax loss of $1.1 million. The following table summarizes the impact of our commodity derivatives for each of the last three years (in thousands):

	2015	2014	2013
Derivative fair value income (loss) per consolidated statements of operations	$416,364	$383,520	$(61,825)
Non-cash fair value (loss) gain: [(1)]			
Natural gas derivatives	$(43,310)	$256,481	$(1,149)
Oil derivatives	(89,880)	135,656	(6,129)
NGLs derivatives	17,432	34,017	(23,291)
Total non-cash fair value (loss) gain [(1)]	$(115,758)	$426,154	$(30,569)
Net cash receipt (payment) on derivative settlements:			
Natural gas derivatives	$339,031	$(58,442)	$(8,090)
Oil derivatives	151,117	2,371	(10,600)
NGLs derivatives	41,974	13,437	(12,566)
Total net cash receipt (payment)	$532,122	$(42,634)	$(31,256)

(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 $92.1 million in 2015 compared to $130.5 million in 2014 and $116.6 million in 2013. The 2015 period includes $90.9 million of revenue primarily from the sale of natural gas that is not related to our production (brokered). These revenues declined from 2014 with significantly lower sales prices partially offset by higher brokered volumes. The 2014 period includes $123.1 million of revenue from the sale of brokered gas and revenue of $15.8 million from the sale of transportation capacity where we have taken firm transportation capacity ahead of production volumes. These revenues increased from 2013 due to an increase in brokered natural gas prices partially offset by lower brokered volumes.

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,			
	2015	2014	Change	% Change	2014	2013	Change	% Change
Direct operating expense	$0.27	$0.35	$ (0.08)	(23 %)	$0.35	$0.37	$ (0.02)	(5 %)
Production and ad valorem tax expense	0.07	0.11	(0.04)	(36 %)	0.11	0.13	(0.02)	(15 %)
General and administrative expense	0.38	0.50	(0.12)	(24 %)	0.50	0.85	(0.35)	(41 %)
Interest expense	0.33	0.40	(0.07)	(18 %)	0.40	0.51	(0.11)	(22 %)
Depletion, depreciation and amortization expense	1.14	1.30	(0.16)	(12 %)	1.30	1.44	(0.14)	(10 %)

Direct operating expense was $136.4 million in 2015 compared to $150.5 million in 2014 and $128.1 million in 2013. 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 repairs. On an absolute basis, our direct operating expenses for 2015 decreased 9% from the prior year with an increase in the number of producing wells and higher water handling costs more than offset by lower workover costs, lower well service costs, lower field personnel and stock-based compensation expenses and the sale of certain non-core assets in second quarter 2014. On an absolute basis, our direct operating expenses for 2014 increased 17% from the same period of the prior year due to an increase in producing wells, higher workovers, water hauling and personnel costs. We incurred $7.3 million of workover costs in 2015 compared to $11.5 million of workover costs in 2014 and $8.6 million in 2013.

On a per mcfe basis, operating expense for 2015 decreased $0.08 or 23% from the same period of 2014, with the decrease consisting of lower well service costs, lower field personnel costs and lower workover costs somewhat offset by higher water handling costs. On a per mcfe basis, operating expense for 2014 decreased $0.02 or 5% from the same period of 2013, with the decrease consisting of lower well services and non-recurring 2013 nitrogen injection costs. We expect to continue to experience lower costs per mcfe as we increase production from our Marcellus Shale wells due to their lower operating cost relative to our other operating areas somewhat offset by higher operating costs on our liquids-rich wells. Stock-based compensation expense represents the amortization of restricted stock 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,			
	2015	2014	Change	% Change	2014	2013	Change	% Change
Lease operating expense	$0.25	$0.31	$ (0.06)	(19 %)	$0.31	$0.34	$ (0.03)	(9 %)
Workovers	0.01	0.03	(0.02)	(67 %)	0.03	0.02	0.01	50 %
Stock-based compensation (non-cash)	0.01	0.01	¾	¾	0.01	0.01	¾	¾
Total direct operating expense	$0.27	$0.35	$ (0.08)	(23 %)	$0.35	$0.37	$ (0.02)	(5 %)

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, 2015 includes $23.7 million ($0.05 per mcfe) impact fee compared to $27.3 million ($0.06 per mcfe) in the year ended December 31, 2014. Production and ad valorem taxes (excluding the impact fee) were $10.1 million in 2015 compared to $17.2 million in 2014. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) decreased to $0.02 in 2015 compared to $0.04 in 2014 due to an increase in production volumes not subject to production or ad valorem taxes and lower prices. The year ended December 31, 2014 includes $27.3 million ($0.06 per mcfe) impact fee compared to $28.0 million ($0.08 per mcfe) impact fee in the year ended December 31, 2013. Production and ad valorem taxes (excluding the impact fee) was $17.2 million in both 2014 and 2013. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) decreased to $0.04 in 2014 compared to $0.05 in 2013 due to an increase in production volumes not subject to production or ad valorem taxes.

General and administrative expense was $194.0 million for 2015 compared to $213.4 million for 2014 and $291.2 million in 2013. The decrease in 2015, when compared to 2014, is primarily due to lower salaries and benefits of $4.6 million, lower public relations costs of $3.1 million, lower legal expenses (including fines) of $6.2 million, lower stock-based compensation costs of $5.7 million and lower office expenses which were partially offset by higher bad debt expenses. The decrease in 2014, when compared to 2013, is primarily due to lower lawsuit settlements of $88.9 million partially offset by an additional $5.9 million of fines for water impoundment leaks and other water sourcing penalties in Pennsylvania and higher salaries and benefits for our employees. Our number of general and administrative employees decreased 16% during 2015. Stock-based compensation expense represents the amortization of PSUs, restricted stock and SARs 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,			
	2015	2014	Change	% Change	2014	2013	Change	% Change
General and administrative	$0.28	$0.37	$(0.09)	(24%)	$0.37	$0.43	$(0.06)	(14%)
Oklahoma legal settlement	¾	¾	¾	¾%	¾	0.26	(0.26)	(100%)
Stock-based compensation (non-cash)	0.10	0.13	(0.03)	(23%)	0.13	0.16	(0.03)	(19%)
Total general and administrative expense	$0.38	$0.50	$(0.12)	(24%)	$0.50	$0.85	$(0.35)	(41%)

Interest expense was $166.4 million for 2015 compared to $169.0 million for 2014 and $176.6 million in 2013. The following table presents information about interest expense per mcfe for each of the last three years:

	Year Ended December 31,		
	2015	2014	2013
Bank credit facility	$0.04	$0.04	$0.04
Senior notes	0.05	¾	¾
Senior subordinated notes	0.23	0.34	0.44
Amortization of deferred financing costs and other	0.01	0.02	0.03
Total interest expense	$0.33	$0.40	$0.51
Average debt outstanding (in thousands)	$3,467,175	$3,141,562	$3,016,249
Average interest rate [a]	4.6%	5.1%	5.6%

[a] Includes commitment fees but excludes debt issue costs and amortization of discount.

On an absolute basis, the decrease in interest expense for 2015 from the same period of 2014 was primarily due to lower interest rates partially offset by higher outstanding debt balances. In July 2015, we redeemed all $500.0 million of 6.75% senior subordinated notes due 2020 (the “6.75% Notes”). In May 2015, we issued $750.0 million of 4.875% senior notes due 2025. We used the proceeds for general corporate purposes and our redemption of our 6.75% notes. Interest expense in 2015 includes interest incurred for both the 6.75% Notes and the 4.875% senior notes due 2025 for two months.

The decrease in interest expense for 2014 from the same period of 2013 was primarily due to lower interest rates. In June 2014, we redeemed all $300.0 million of our outstanding 8.0% senior subordinated notes due 2019. In March 2013, we issued $750.0 million of 5.0% senior subordinated notes due 2023. We used the proceeds for general corporate purposes and to retire outstanding balances on our bank debt which carries a lower interest rate. In May 2013, we redeemed all $250.0 million of our 7.25% senior subordinated notes due 2018.

The 2015 and 2013 note issuances were undertaken to reduce interest costs, lengthen our maturities and to give us greater liquidity for the near term. Average debt outstanding on the bank credit facility for 2015 was $847.8 million compared to $646.6 million for 2014 and $441.0 million for 2013 and the weighted average interest rate on the bank credit facility was 1.7% for 2015 compared to 2.0% in both 2014 and 2013.

Depletion, depreciation and amortization (“DD&A”) was $581.2 million in 2015 compared to $551.0 million in 2014 and $492.4 million in 2013. The increase in 2015 when compared to 2014 is due to a 20% increase in production somewhat offset by a 12% decrease in depletion rates. The increase in 2014 when compared to 2013 is due to a 24% increase in production somewhat offset by a 10% decrease in depletion rates.

On a per mcfe basis, DD&A decreased to $1.14 in 2015 compared to $1.30 in 2014 and $1.44 in 2013. Depletion expense, the largest component of DD&A, was $1.08 per mcfe in 2015 compared to $1.23 per mcfe in 2014 and $1.37 per mcfe in 2013. We have historically adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and 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 $0.95 per mcfe in 2016, based on our current production estimates. In areas where we are actively drilling, such as the Marcellus Shale area, our fourth quarter adjusted 2015 depletion rates were lower than the fourth quarter 2014 and 2013 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 2015 when compared to 2014 and 2013 is due to the mix of our production from our properties with lower depletion rates and impairment of properties in 2015 which reduced our carrying values. The following table summarizes DD&A expenses per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2015	2014	Change	% Change	2014	2013	Change	% Change
Depletion and amortization	$1.08	$1.23	$(0.15)	(12%)	$1.23	$1.37	$(0.14)	(10%)
Depreciation	0.02	0.03	(0.01)	(33%)	0.03	0.04	(0.01)	(25%)
Accretion and other	0.04	0.04	¾	¾%	0.04	0.03	0.01	33%
Total DD&A expenses	$1.14	$1.30	$(0.16)	(12%)	$1.30	$1.44	$(0.14)	(10%)

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, termination costs, deferred compensation plan expenses, loss on early extinguishment of debt and impairment of proved properties.

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, 2015 (in thousands):

	2015	2014	2013
Direct operating expense	$2,780	$4,208	$2,755
Brokered natural gas and marketing expense	2,132	3,523	1,852
Exploration expense	2,985	4,569	4,025
General and administrative expense	49,687	55,382	55,737
Termination costs	217	2,999	—
Total stock-based compensation	$57,801	$70,681	$64,369

Stock-based compensation includes the amortization of restricted stock grants, SARs and PSUs grants. The year ended December 31, 2014 also includes $6.7 million of awards granted to our former executive chairman for his service in 2013 while he was a Range officer, which were fully vested upon grant.

Brokered natural gas and marketing expense was $115.9 million in 2015 compared to $130.0 million in 2014 and $131.8 million in 2013. The decrease in these costs from 2014 to 2015 reflects significantly lower purchase prices partially offset by higher brokered gas volumes and higher expenses related to company owned gathering lines. The year ended December 31, 2014 also includes $9.3 million of transportation capacity expenses where we took firm transportation capacity ahead of our production. The decrease in these costs from 2013 to 2014 is due to a decrease in the purchase of natural gas used to blend our residue gas in Pennsylvania offset by higher broker gas volumes, higher personnel costs of our marketing staff, an increase in transportation capacity expenses where we have taken firm transportation capacity ahead of production volumes and higher expenses related to company owned gathering lines. Stock-based compensation represents the amortization of PSUs, restricted stock grants and SARs as part of the compensation of our marketing staff.

Exploration expense was $21.4 million in 2015 compared to $63.5 million in 2014 and $64.4 million in 2013. Exploration expense was lower in 2015 when compared to 2014 due to lower seismic costs, lower delay rentals and lower exploratory dry hole costs. Exploration expense was lower in 2014 when compared to 2013 due to lower seismic costs somewhat offset by higher dry hole costs and delay rentals. For the year ended December 31, 2014, delay rentals and other includes expense of $7.0 million related to a suspended exploratory well which was impaired because we were no longer making sufficient progress in gaining access to transportation facilities to allow the continued capitalization of such costs. Stock-based compensation represents the amortization of PSUs, restricted stock grants and SARs 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, 2015 (in thousands):

	Year Ended December 31,				Year Ended December 31,			
	2015	2014	Change	% Change	2014	2013	Change	% Change
Seismic	$1,731	$19,504	$(17,773)	(91%)	$19,504	$26,872	$(7,368)	(27%)
Delay rentals and other	4,709	15,488	(10,779)	(70%)	15,488	12,969	2,519	19%
Personnel expense	11,894	14,821	(2,927)	(20%)	14,821	14,844	(23)	—
Stock-based compensation expense	2,985	4,569	(1,584)	(35%)	4,569	4,025	544	14%
Exploratory dry hole expense	87	9,166	(9,079)	(99%)	9,166	5,699	3,467	61%
Total exploration expense	$21,406	$63,548	$(42,142)	(66%)	$63,548	$64,409	$(861)	(1%)

Abandonment and impairment of unproved properties was $47.6 million in 2015 compared to $47.1 million in 2014 and $51.9 million in 2013. 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. 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 will likely be recorded. In second quarter 2013, we impaired individually significant unproved properties in East Texas for $5.4 million.

Termination costs in 2015 includes $3.1 million of accrued building lease costs for our Oklahoma City office which was closed in the first half of 2015, additional severance of $11.7 million and stock-based compensation of $217,000 for accelerated vesting of equity grants for our Oklahoma City office employees and other areas where we have determined a need to reduce personnel due, in part, to the lower commodity price environment. Termination costs in 2014 includes an accrual for estimated severance costs of $5.4 million related to the closing of our Oklahoma City office which was announced in first quarter 2015 and $3.0 million of non-cash stock compensation expense related to the accelerated vesting of PSUs, restricted stock grants and SARs as part of the severance benefit for these Oklahoma City personnel.

Deferred compensation plan expense was a gain of $77.6 million in 2015 compared to a gain of $74.6 million in 2014 and a loss of $55.3 million in 2013. Our stock price decreased to $24.61 at December 31, 2015 compared to $53.45 at December 31, 2014. Our stock price decreased to $53.45 at December 31, 2014 compared to $84.31 at December 31, 2013. 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.

Loss on early extinguishment of debt was $22.5 million in 2015 compared to $24.6 million in 2014 and $12.3 million in 2013. In August 2015, we redeemed our 6.75% senior subordinated notes due 2020 at 103.375% of par and we recorded a loss on extinguishment of debt of $22.5 million which includes a call premium and expensing of deferred financing costs on the repurchased debt. In June 2014, we redeemed all of our $300.0 million aggregate principal amounts of our 8.0% senior subordinated notes due 2019 at a price equal to 104.0% of par and we recorded a loss on extinguishment of debt of $24.6 million, which includes a call premium and expensing of related deferred financing costs on the repurchased debt. In May 2013, we redeemed all of our $250.0 million aggregate principal amount of our 7.25% senior subordinated notes due 2018 at 103.625% of par and we recorded a loss on extinguishment of debt of $12.3 million, which includes a call premium and the expensing of related deferred financing costs on the repurchased debt.

Impairment of proved properties increased to $590.2 million in 2015 compared to $28.0 million in 2014 and $7.8 million in 2013. Due to a significant decline in commodity prices in 2015, we recorded $306.6 million of impairment charges related to our oil and natural gas properties in Northern Oklahoma, $195.6 million related to our legacy shallow producing assets in Northwest Pennsylvania, $86.9 million related to oil and natural gas properties in the Texas Panhandle and $1.1 million related to assets in South Texas in the year ended December 31, 2015. The year ended December 31, 2014 includes impairment charges of $5.5 million related to our properties in Mississippi, $18.5 million related to certain West Texas properties and $4.0 million to fully impair our remaining North Texas oil and gas properties. The year ended December 31, 2013 includes a $7.0 million impairment related to certain South

Texas wells. The year ended December 31, 2013 also includes $741,000 impairment expense related to surface acreage in North Texas. These assets were evaluated for impairment due to declining reserves, natural gas and oil prices and changes in projected capital spending and, in the case of certain of our North Texas and West Texas properties, the possibility of a sale. The cash flows we use to assess proved property impairment includes 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.

Income tax expense was a benefit of $338.7 million in 2015 compared to income tax expense of $396.5 million in 2014 and $33.9 million in 2013. The 2015 decrease in income taxes reflects a $2.1 billion decrease in income before income taxes when compared to the same period of 2014. The 2014 increase in income taxes reflects a $881.3 million increase in income before income taxes when compared 2013. The effective tax rate was 32.2% in 2015 compared to 38.5% in 2014 and 22.6% in 2013. For the year ended December 31, 2015 and December 31, 2014, current income tax expense relates to state income taxes. For the year ended December 31, 2013, the current income tax benefit of $143,000 represents a refund of state income taxes. The 2015, 2014 and 2013 effective tax rate was different than the statutory tax rate due to state income taxes. Our tax rates were also affected in 2015 and 2014 by decreases in our valuation allowance related to our deferred tax asset for future deferred compensation plan distributions of senior executives to the extent their estimated future compensation (including these distributions) would exceed the $1.0 million deductible limit provided under Section 162(m) of the Internal Revenue Code of 1986, as amended, compared to an increase in the valuation allowance in 2013. Our effective tax rates are also impacted by adjustments to our state apportionment rates which was an expense of $2.0 million in 2015 compared to a benefit of $2.0 million in 2014 and a benefit of $21.2 million in 2013. In 2015, we have increased our deferred tax valuation allowances by $32.7 million for state net operating loss carryforwards and credits and by $42.5 million for federal net operating loss carryforwards which we do not believe are realizable. We estimate our ability to utilize our federal and state loss carryforwards by forecasting the future reversal of our temporary differences as compared to our loss carryforward expiration dates. 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 39% for 2016, before any discrete tax items.

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):

	2015	2014	2013
Sources of cash and cash equivalents			
Operating activities	$683,700	$954,135	$743,538
Disposal of assets	890,901	180,508	315,522
Borrowing on credit facility	2,271,000	2,107,000	1,684,000
Issuance of debt	750,000	¾	750,000
Issuance of common stock	¾	396,562	343
Other	37,541	48,522	60,791
Total sources of cash and cash equivalents	$4,633,142	$3,686,727	$3,554,194
Uses of cash and cash equivalents			
Additions to natural gas and oil properties	$(1,030,644)	$(1,200,419)	$(1,159,252)
Acreage purchases	(74,880)	(211,971)	(132,145)

Other property	(4,441)	(11,863)	(5,925)
Debt repayments	(516,875)	(312,000)	(259,063)
Repayments on credit facility	(2,899,000)	(1,884,000)	(1,923,000)
Dividends paid	(27,083)	(26,610)	(26,129)
Other	(80,196)	(39,764)	(48,584)
Total uses of cash and cash equivalents	$(4,633,119)	$(3,686,627)	$(3,554,098)

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 since 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 large 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 2015, we have entered into additional natural gas and NGLs hedges for 2016 and 2017. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowings under the bank credit facility. As of December 31, 2015, we have entered into hedging agreements covering 305.9 Bcfe for 2016 and 8.4 Bcfe for 2017.

Net cash provided from operating activities in 2015 was $683.7 million compared to $954.1 million in 2014 and $743.5 million in 2013. The decrease in cash provided from operating activities from 2014 to 2015 reflects significantly lower realized prices (a decline of 34%) partially offset by a 20% increase in production and lower expenses. The increase in cash provided from operating activities from 2013 to 2014 reflects a 24% increase in production and lower lawsuit settlements partially offset by lower realized prices (a decline of 13%). 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 2015 was a negative $16.8 million compared to a negative $31.0 million for 2014 and negative $42.8 million in 2013.

Disposal of assets in 2015 includes $876.0 million of proceeds received from the sale of our Virginia and West Virginia properties, before closing adjustments, which closed on December 30, 2015. In 2014, net proceeds were related to the Conger Exchange where we received $145.0 million in cash proceeds plus assets and in 2013 we received proceeds of $275.0 million from the sale of our southeast New Mexico and certain West Texas properties. For additional details related to our dispositions, see Note 3 to our consolidated financial statements.

Issuance of debt in 2015 includes the issuance of $750.0 million aggregate principal amount of 4.875% senior notes due 2025. In 2013, we issued $750.0 million aggregate principal amount of 5.0% senior subordinated notes due 2023. For additional information, see Note 7 to our consolidated financial statements.

Issuance of common stock in 2014 includes the issuance of 4.56 million shares of common stock where we received proceeds of $396.6 million.

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. 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):

	2015	2014	2013
Appalachian	$786,457	$1,219,928	$949,863
Other	22,653	94,030	225,633
Total	809,110	1,313,958	1,175,496
Change in capital expenditure accrual for proved properties	221,534	(113,539)	(16,244)
Additions to natural gas and oil properties	$1,030,644	$1,200,419	$1,159,252

Debt repayments in 2015 includes the redemption of $500.0 million of our outstanding 6.75% senior subordinated notes due 2020 compared to the redemption of $300.0 million of our outstanding 8.0% senior subordinated notes due 2019 in 2014 and the redemption of $250.0 million of our outstanding 7.25% senior subordinated notes due 2018 in 2013. See Note 7 to our consolidated financial statement for additional information on debt repayments.

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. 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. 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. Recently, natural gas and crude oil prices have remained depressed. Historically, in periods of falling prices, the demand for drilling rigs, oilfield supplies and drill pipe declines but its decline lags significantly behind the declines in natural gas and crude oil prices. We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our 2016 capital budget is $495.0 million. Actual capital expenditure levels may vary significantly 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. We may, from time to time, depending on market conditions, our liquidity requirements, contractual restrictions and other factors, seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other debt or equity securities in open market purchases, privately negotiated transactions or otherwise. The amounts involved may be material.

During 2015, we:

- received proceeds from the sale of non-strategic assets of $890.9 million;
- redeemed all $500.0 million aggregate principle amount of 6.75% senior subordinated notes due 2020; and
- issued $750.0 million aggregate principal amount of 4.875% senior notes due 2025.

In response to the lower commodity price environment, we were proactive in adjusting our 2015 capital budget which was originally announced in December 2014 from $1.3 billion to $870 million. 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 2019 (2) we have commodity derivatives in place which cover a portion of our 2016 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 six years or more and such notes carry attractive fixed interest rates ranging from 4.875% to 5.75%.

Credit Arrangements

Long-term debt at December 31, 2015 totaled $2.7 billion, including $86.4 million of bank credit facility debt, $1.8 billion of senior subordinated notes and $738.1 million of senior notes. As of December 31, 2015, 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, 2015, we also have $137.9 million of undrawn letters of credit. The bank credit facility is secured by substantially all of our assets and has a maturity date of October 16, 2019. 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 and our subordinated notes impose limitations on the payment of dividends and other restricted payments (as defined under the debt agreements for our bank debt and our subordinated notes). 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, 2015.

Our senior subordinated notes, which were issued pursuant to an indenture, include a limitation on the amount of credit facility debt we can incur. Certain thresholds, as set forth in the indenture debt incurrence test, may limit our ability to incur debt under our bank credit facility in excess of a $1.5 billion floor amount based on the levels of commodity prices for natural gas, NGLs and crude oil used in the annual calculation of discounted future cash flows relating to proved oil and gas reserves. Given this indenture provision, our bank credit facility usage is currently limited to $1.5 billion until higher prices or proved reserve additions increase discounted future net cash flows.

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,		
	2015	2014	2013
		(Mmcfe)	
Proved Reserves:			
Beginning of year	10,310,229	8,202,274	6,505,570
Reserve additions	1,265,348	2,398,709	1,732,944
Reserve revisions	(211,163)	90,822	448,898
Purchases	¾	262,813	¾
Sales	(963,423)	(220,122)	(142,116)
Production	(509,328)	(424,267)	(343,022)
End of year	9,891,663	10,310,229	8,202,274
Proved Developed Reserves:			
Beginning of year	5,349,761	4,192,666	3,457,502
End of year	5,422,075	5,349,761	4,192,666

Our proved reserves at year-end 2015 were 9.9 Tcfe compared to 10.3 Tcfe at year-end 2014 and 8.2 Tcfe at year-end 2013. Natural gas comprised approximately 63%, 67% and 69% of our proved reserves at year-end 2015, 2014 and 2013.

Reserve Additions and Revisions. During 2015, we added approximately 1.3 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 80% of 2015 reserve additions was attributable to natural gas. Included in 2015 proved reserves is a total of 292.8 Mmbbls of ethane reserves (1,296 Bcfe) in the Marcellus Shale, which represents reserves that match volumes delivered under our existing long term, extendable contracts. Revisions of previous estimates of a net reduction of 211 Bcfe includes negative pricing revisions and 1.2 Tcfe of reserves reclassified to unproved because of reduced future capital spending due to lower commodity prices partially offset by improved recovery for our Marcellus Shale natural gas properties of 781.0 Bcfe and positive performance revisions.

During 2014, we added approximately 2.4 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 58% of 2014 reserve additions was attributable to natural gas. Included in 2014 proved reserves is a total of 1,170 Bcfe of ethane reserves (264.3 Mmbbls) in the Marcellus Shale. Revisions of previous estimates of a net 91 Bcfe includes positive performance revisions and improved recovery primarily for our Marcellus Shale natural gas properties and positive price revisions, somewhat offset by reserves of 611 Bcfe reclassified to unproved as we continue to see success from drilling longer laterals, increasing the number of hydraulic fracturing stages and better lateral targeting caused some previously planned wells to not be drilled within the original five-year development horizon.

During 2013, we added 1.7 Tcfe of proved reserves from drilling activities and evaluation of proved areas, primarily in the Marcellus Shale. Approximately 49% of the 2013 reserve additions was attributable to natural gas. Revisions of previous estimates of 449 Bcfe for the year ended December 31, 2013 consists of positive performance revisions, positive price revisions and improved recovery, partially offset by reserves reclassified to unproved because of a slower pace of development activity beyond the five-year development horizon. We added 369 Bcfe of incremental ethane reserves under additional ethane contracts in Appalachia.

Purchases. In 2014, we purchased 262.8 Bcfe of reserves primarily related to the Conger Exchange where we received producing properties in Virginia.

Sales. In 2015, we sold 963.4 Bcfe of reserves primarily related to our Virginia and West Virginia natural gas and oil properties. In 2014, we sold 220.1 Bcfe of reserves primarily related to the sale of our Conger properties in Glasscock and Sterling Counties, Texas. In 2013, we sold 142.1 Bcfe of reserves related to the sale of certain of our Permian Basin and New Mexico properties.

Future Net Cash Flows. At December 31, 2015, the present value (discounted at 10%) of estimated future net cash flows from our proved reserves was $3.0 billion. The present value of our estimated future net cash flows at December 31, 2014 was $10.1 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. At December 31, 2015, the after-tax present value of estimated future net cash flows from our proved reserves was $2.7 billion compared to $7.6 billion at December 31, 2014.

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, 2015 and 2014, our total debt and capitalization were as follows (in thousands):

	2015	2014
Bank debt	$86,427	$713,221
Senior notes	738,101	¾
Senior subordinated notes	1,826,775	2,317,603
Total debt	2,651,303	3,030,824
Stockholders' equity	2,759,658	3,457,429
Total capitalization	$5,410,961	$6,488,253
Debt to capitalization ratio	49.0 %	46.7 %

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 2015, we paid $27.1 million in dividends to our common stockholders ($0.04 per share per quarter). In 2014, we paid $26.6 million in dividends to our common stockholders ($0.04 per share each quarter). In 2013, we paid $26.1 million in dividends to our common stockholders ($0.04 per share each quarter). In February 2016, the board of directors reduced our quarterly dividend amount from $0.04 per share to $0.02 per share.

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, derivative obligations, asset retirement obligations and transportation and gathering commitments. As of December 31, 2015, 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, 2015, we had a total of $137.9 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, 2015. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2015 reflects accrued interest payable on our bank debt of $697,000 which is payable in first quarter 2016. We expect to make interest payments of $28.8 million per year on our 5.75% senior subordinated notes, $67.5 million per year on our 5.0% senior subordinated notes and $36.6 million per year on our 4.875% senior notes.

The following summarizes our contractual financial obligations at December 31, 2015 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					
	2016	2017	2018	2019 and 2020	Thereafter	Total
Debt:						
Bank debt due 2019 [(a)]	$¾	$¾	$¾	$95,000	$¾	$95,000
5.75% senior subordinated notes due 2021	¾	¾	¾	¾	500,000	500,000
5.0% senior subordinated notes due 2022	¾	¾	¾	¾	600,000	600,000
5.0% senior subordinated notes due 2023	¾	¾	¾	¾	750,000	750,000
4.875% senior notes due 2025	¾	¾	¾	¾	750,000	750,000
Other obligations:						

Operating leases	11,819	10,014	8,902	14,502	29,258	74,495
Transportation and gathering commitments	407,046	401,517	366,914	726,157	1,748,559	3,650,193
Other purchase obligations	1,046	94	33	¾	¾	1,173
Asset retirement obligation liability [(b)]	15,071	76	¾	148	248,842	264,137
Total contractual obligations [(c)]	$434,982	$411,701	$375,849	$ 835,807	$4,626,659	$ 6,684,998

(a) Due at termination date of our bank credit facility. Interest paid on our bank credit facility would be approximately $1.7 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 8 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 transportation and gathering agreements which are contingent on certain pipeline and gathering line modifications and/or construction. These agreements range between six-year and twenty-year terms which are expected to begin in 2016 and 2017. Based on these contracts, we will have additional transportation obligations for natural gas volumes of 2.0 bcf per day until 2026, declining to 1.3 bcf per day through 2032 and 400,000 mcf per day until 2037. We also have gathering obligations which begin in 2017 of up to 400,000 mcf per day until 2032. Beginning

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in 2016, we also have transportation obligations for ethane volumes of 20,000 bbls per day and propane volumes of 20,000 bbls per day through the end of 2031.

Delivery Commitments

We have various volume delivery commitments that are related to our Marcellus Shale, Oklahoma and Texas 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, 2015, our delivery commitments through 2028 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2016	405,126	40,000
2017	241,301	40,000
2018	¾	40,000
2019	¾	20,000
2020	¾	20,000
2021	¾	20,000
2022 - 2028	¾	15,000

In addition to the amounts included in the above table, we have contracted with several pipeline companies through 2033 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 20,000 bbls per day starting in 2016, increasing to 30,000 bbls per day in late 2018 and 45,000 bbls per day in 2020 through the end of the term. 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 50,000 mcf per day starting in 2017 and increasing to 200,000 mcf per day in early 2019 and 300,000 mcf per day in late 2019.

Other

We lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three to 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 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, 2015, we had $2.7 billion of debt outstanding. Of this amount, $2.6 billion bears interest at fixed rates averaging 5.1%. Bank debt totaling $95.0 million bears interest at floating rates, which averaged 1.8% at year-end 2015. The 30-day LIBOR rate on December 31, 2015 was 0.4%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2015 would cost us approximately $950,000 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 2016 to continue to be a function of supply and demand. Recently, natural gas and oil prices have remained depressed and we continue to experience a decline in our cost structure. Historically, the demand for drilling rigs, completion services, oilfield supplies and drill pipe is expected to decline with falling commodity prices but such decline tends to lag behind the declines in natural gas, NGLs and oil prices.

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 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, including the rule revisions designed to modernize the oil and gas company reserves reporting requirements which we adopted effective December 31, 2009, 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 Chairman, President and Chief Executive Officer. For additional discussion, see "Proved Reserves," in Items 1 and 2 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 2015 compared to 96% in 2014 and 96% in 2013. 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, 2015, we estimate that a 1% change in proved reserves would increase or decrease 2016 depletion expense by approximately $4.8 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 18 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 judgements and assumptions are inherent, and to some extent, interdependent of one another in our estimate of future cash flows. The use of alternate judgements 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. Our recorded impairment of producing natural gas and oil properties was $590.2 million in 2015 compared to $28.0

million in 2014 and $7.0 million in 2013. In 2015, an impairment of $306.6 million was recorded related to natural gas and oil properties in Northern Oklahoma, $195.6 million of impairment expense related to our shallow legacy oil and natural gas assets in Northwest Pennsylvania, $86.9 million related to our assets in the Texas Panhandle and $1.1 million related to onshore Gulf Coast properties. Our 2015 impairment expense was due to significantly lower natural gas and oil prices. In 2014, an impairment of $5.5 million was recorded on our Mississippi properties due to lower reserves, an impairment of $18.5 million was recorded on certain West Texas properties due to lower reserves which also considered the possibility of a sale of these properties and an impairment of $4.0 million to fully write-down our remaining oil and natural gas properties in North Texas. In 2013, an impairment of $7.0 million was recorded on certain South Texas properties due to lower reserves and we also recorded a $741,000 impairment of remaining surface acreage in North Texas. 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. 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. We have recorded abandonment and impairment expense related to unproved properties of $47.6 million in 2015 compared to $47.1 million in 2014 and $51.9 million in 2013.

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 that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair 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; and
- recorded value of derivative instruments.

Natural Gas 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 the 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 2015, we increased our existing ARO by $16.0 million or approximately 6% of the ARO balance at December 31, 2014. This was primarily due to an increase in the estimated costs to reclaim our water impoundments. During 2014, we increased our existing ARO by $48.3 million or approximately 21% of the ARO at December 31, 2013. This increase was due to an increase in the estimated costs to plug and abandon our wells. See Note 8 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 net income 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. When recording income tax expense, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit, which can take years to complete, and future events often impact the timing of when income tax expenses and benefits are recognized. We have recorded deferred tax assets and liabilities for temporary differences between book basis and tax basis, tax credit carryforwards and operating loss carryforwards. We have deferred tax assets relating to tax operating loss carryforwards and other deductible differences. We routinely assess the realizability of our deferred tax assets and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. In assessing the need for additional or adjustments to existing valuation allowances, we consider the preponderance of evidence concerning the realization of the deferred tax asset. We must consider any prudent and feasible tax planning strategies that might minimize the amount of any valuation allowance recognized against deferred tax assets. At December 31, 2015, we had a tax basis of $2.2 billion related to prior years capitalized intangible drilling costs, which will be amortized over the next five years.

Our net deferred tax assets, after valuation allowances, are expected to be realized through the reversal of temporary differences. During 2015, we recognized a $42.5 million valuation allowance related to our federal net operating loss carryforwards. In addition, we increased our valuation allowance we had against our state net operating loss carryforwards and credits from $8.8 million as of December 31, 2014 to $41.5 million as of December 31, 2015. The valuation allowances impacted our consolidated effective tax rate for the year ended December 31, 2015. See Note 4 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, gains 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.

Revenue Recognition

Natural gas, NGLs and oil sales are recognized when we deliver our production to the customer 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. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. We report our gathering and transportation costs in accordance with Accounting Standards Code Section 605-45-05 of Subtopic 605-45 for Revenue Recognition. One type of agreement is a netback arrangement, under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the net price we received from the purchaser. In the case of NGLs, we receive a net price from the purchaser (which is net of processing costs) which is recorded as revenue at the net price. Under the other arrangement, we sell natural gas or oil at a specific delivery point, pay transportation, gathering and compression to a third party and receive proceeds from the purchaser with no deduction. In that case, we record revenue at the price received from the purchaser and record these third party costs as transportation, gathering and compression expense.

Stock-based Compensation Arrangements

The fair value of performance share unit awards 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 stock-settled stock appreciation rights is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The models employ various assumptions, based on management’s best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the award. We have utilized historical data and analyzed current information to reasonably support these assumptions. The fair value of restricted stock awards is determined based on the fair market value of our common stock on the date of grant. The fair value of restricted stock unit grants 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

In May 2014, an accounting standards update was issued that supersedes the existing revenue recognition requirements. This standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. Among other things, the standard also eliminates industry-specific revenue guidance, requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively and improves guidance for multiple-element arrangements. This standard is effective for us in first quarter 2018 and should be applied retrospectively to each prior reporting period presented or with the cumulative effect of initially applying the update recognized at the date of initial application. Early adoption is permitted with an effective date no earlier than first quarter 2017. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our consolidated results of operations, financial position or cash flows.

In August 2014, an accounting standards update was issued that requires management to assess an entity’s ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in United States auditing standards. This standard is effective for us in first quarter 2017 and early adoption is permitted. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

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. 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. 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 63% of our December 31, 2015 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, 2014 to December 31, 2015.

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. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. 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 establishes a minimum floor price and a predetermined ceiling price. At December 31, 2015, our derivatives program includes swaps. These contracts expire monthly through December 2017. Their fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2015, approximated a net unrealized pretax gain of $283.3 million compared to a pretax gain of $401.7 million at December 31, 2014. This change is primarily related to the settlements of derivative contracts during 2015 and to the natural gas, NGLs and oil futures prices as of December 31, 2015, in relation to the new commodity derivative contracts we entered into during 2015 for 2016 and 2017. At December 31, 2015, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price	Fair Market Value (in thousands)
Natural Gas				
2016	Swaps	745,874 Mmbtu/day	$ 3.24	$204,067
2017	Swaps	20,000 Mmbtu/day	$ 3.49	$5,045
Crude Oil				
2016	Swaps	4,247 bbls/day	$ 65.27	$37,170
2017	Swaps	500 bbls/day	$ 55.00	$1,529
NGLs (C3 - Propane)				
2016	Swaps	5,500 bbls/day	$ 0.60/gallon	$15,884
NGLs (C4 – Normal Butane)				
2016	Swaps	2,500 bbls/day	$0.72/gallon	$6,968
NGLs (C5 - Natural Gasoline)				
2016	Swaps	2,749 bbls/day	$ 1.20/gallon	$12,613

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 markets.

Currently, the Appalachian region has limited local demand and infrastructure to accommodate ethane. We have previously announced three ethane agreements wherein we have contracted to either sell or transport ethane from our Marcellus Shale area, two of which began operations in late 2013. The remaining facility is expected to begin operations in early 2016. We cannot assure you that these facilities will become or remain available. 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 natural gas to blend with our rich residue gas from the Southwest Marcellus Shale in order to meet pipeline specifications.

Other Commodity Risk

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. 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 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 was a gain of $5.5 million at December 31, 2015, the volumes are for 53,365,000 Mmbtu and they expire monthly through March 2017.

At December 31, 2015, we also had propane basis swap contracts that are not designated for hedge accounting, which lock in the differential between Mont Belvieu and international propane indexes. The contracts settle monthly through December 2016 and include total volume of 4,679 bbls/day. The fair value of these contracts was a loss of $1.1 million on December 31, 2015.

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, 2015. 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		Hypothetical Change in Fair Value	
		Increase in Commodity Price of		Decrease in Commodity Price of	
	Fair Value	10%	25%	10%	25%
Swaps	$283,276	$(86,046)	$(215,095)	$86,126	$215,310
Basis swaps	4,329	(234)	(590)	238	611

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, 2015, our derivative counterparties include seventeen 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.

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 publically traded debt and variable rate bank debt. At December 31, 2015, we had $2.7 billion of debt outstanding. Of this amount, $2.6 billion bears interest at a fixed rate averaging 5.1%. Bank debt totaling $95.0 million bears interest at floating rates, which was 1.8% on that date. On December 31, 2015, the 30-day LIBOR rate was 0.4%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2015 would cost us approximately $950,000 in additional annual interest expense.

The fair value of our subordinated debt is based on year-end December 2015 quoted market prices. The following table presents information on these fair values (in thousands):

	Carrying Value	Fair Value
Fixed rate debt:		
Senior Notes due 2025	$750,000	$572,813

(The interest rate is fixed at a rate of 4.875%)		
Senior Subordinated Notes due 2021 (The interest rate is fixed at a rate of 5.75%)	500,000	396,250
Senior Subordinated Notes due 2022 (The interest rate is fixed at a rate of 5.00%)	600,000	447,000
Senior Subordinated Notes due 2023 (The interest rate is fixed at a rate of 5.00%)	750,000	551,250
	$2,600,000	$1,967,313

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

For financial statements required by Item 8, see Item 15 in Part IV of this report.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2015 at the reasonable assurance level.

Changes in Internal Controls over Financial Reporting. There have been no changes in our system of internal control over financial reporting (such as term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting. See "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting" which appear on pages F-2 and F-3, respectively, under "Item 15. Exhibits, Financial Statements Schedules."

ITEM 9B. OTHER INFORMATION
None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The executive officers and directors are listed below with a description of their experience and certain other information. Each director was elected for a one-year term at the 2015 annual stockholders' meeting. Executive officers are appointed by our board of directors.

	Age	Officer Since	Position
Brenda A. Cline	55	2015	Director
Anthony V. Dub	66	1995	Director
V. Richard Eales	79	2001	Director
Allen Finkelson	69	1994	Director
James M. Funk	66	2008	Lead Independent Director
Christopher A. Helms	61	2014	Director
Jonathan S. Linker	67	2002	Director
Mary Ralph Lowe	69	2013	Director
Gregory G. Maxwell	59	2015	Director
Kevin S. McCarthy	56	2005	Director
John H. Pinkerton	61	1990	Director
Jeffrey L. Ventura	58	2003	Chairman, President and Chief Executive Officer
Roger S. Manny	58	2003	Executive Vice President – Chief Financial Officer
Ray N. Walker, Jr.	58	2010	Executive Vice President – Chief Operating Officer
John K. Applegath	67	2014	Senior Vice President – Southern Marcellus Shale
Alan W. Farquharson	58	2007	Senior Vice President – Reservoir Engineering & Economics
Dori A. Ginn	58	2009	Senior Vice President – Controller and Principal Accounting Officer
David P. Poole	53	2008	Senior Vice President – General Counsel and Corporate Secretary
Chad L. Stephens	60	1990	Senior Vice President – Corporate Development
Rodney L. Waller	66	1999	Senior Vice President and Assistant Secretary

Brenda A. Cline became a director in 2015. Since 1993, Ms. Cline has served as executive vice president, chief financial officer, treasurer, and secretary of the Kimbell Art Foundation, a private operating foundation that owns and operates the Kimbell Art Museum, Fort Worth, Texas. Ms. Cline has also served as an independent trustee of American Beacon Funds since 2004 and currently serves as the chair of the audit and compliance committee. She is a director of Tyler Technologies, Inc., serving on the nominating and governance committee and as the chair of the audit committee. From 1993 until 2013, Ms. Cline served as a contract author for Thomson Reuters, Fort Worth, Texas. Before 1993, Ms. Cline held various positions with Ernst & Young LLP. Ms. Cline also serves on the boards of certain non-profit entities, including on the board of trustees of Texas Christian University and the Pension Fund of the Christian Church. Ms. Cline is a certified public accountant. She received her Bachelor of Business Administration, Accounting degree, summa cum laude, from Texas Christian University.

Anthony V. Dub became a director in 1995. Mr. Dub is Chairman of Indigo Capital, LLC, a financial advisory firm based in New York. Before forming Indigo Capital in 1997, he served as an officer of Credit Suisse First Boston ("CSFB"). Mr. Dub joined CSFB in 1971 and was named a managing director in 1981. Mr. Dub led a number of departments during his 26 year career at CSFB including the investment banking department. After leaving CSFB, Mr. Dub became vice chairman and a director of Capital IQ, Inc. until its sale to Standard & Poor's in 2004. Capital IQ is a leader in helping organizations capitalize on synergistic integration of market intelligence, institutional knowledge and relationships. Mr. Dub received a Bachelor of Arts degree, magna cum laude, from Princeton University.

V. Richard Eales became a director in 2001. Mr. Eales has over 46 years of experience in the energy, technology and financial industries. He is currently retired, having been a financial consultant serving energy and information technology businesses from 1999 through 2002. Mr. Eales was employed by Union Pacific Resources Group Inc. from 1991 to 1999 serving as executive vice president from 1995 through 1999. Before 1991, Mr. Eales served in various financial capacities with Butcher & Singer and Janney Montgomery Scott, investment banking firms, as CFO of Novell, Inc., a technology company, and in the treasury department of Mobil Oil Corporation. Mr. Eales received his Bachelor of Chemical Engineering degree from Cornell University and his Master's degree in Business Administration from Stanford University.

Allen Finkelson became a director in 1994. Mr. Finkelson was a partner at Cravath, Swaine & Moore LLP from 1977 to 2011, with the exception of the period 1983 through 1985, when he was a managing director of Lehman Brothers Kuhn Loeb Incorporated. Mr. Finkelson joined Cravath, Swaine & Moore LLP in 1971. Mr. Finkelson earned a Bachelor of Arts from St. Lawrence University and a J.D. from Columbia University School of Law.

James M. Funk became a director in December 2008 and was elected as lead independent director in 2015. Mr. Funk is an independent consultant and oil and gas producer with over 30 years of experience in the energy industry. Mr. Funk served as senior vice president of Equitable Resources and president of Equitable Production Co. from June 2000 until December 2003. Previously, Mr. Funk was employed by Shell Oil Company for 23 years in senior management and technical positions. Mr. Funk has previously served on the boards of Westport Resources (2000 to 2004) and Matador Resources Company (2003 to 2008). Mr. Funk currently serves as a director of Superior Energy Services, Inc., a public oil field services company headquartered in New Orleans, Louisiana. Mr. Funk received a B.A. degree in Geology from Wittenberg University, a M.S. in Geology from the University of Connecticut and a PhD in Geology from the University of Kansas. Mr. Funk is a certified petroleum geologist.

Christopher A. Helms became a director in July 2014. Mr. Helms has over 38 years of experience in the energy industry, principally in the midstream sector. Mr. Helms is the president and chief executive officer of US Shale Energy Advisors LLC and subsidiaries that own and operate energy midstream and logistics assets. Prior to his retirement in 2012, Mr. Helms was executive vice president and group chief executive officer of NiSource Inc. From 2005 to 2011 he served as chief executive officer and executive director of NiSource Gas Transmission and Storage. Mr. Helms serves as a director of MPLX GP LLC and Questar Corporation. Mr. Helms is a member of the University of Houston Board of Visitors. He has previously served on the boards of Coskata, Inc., Millennium Pipeline Company LLC and Centennial Pipeline Company LLC and as a director of the Marcellus Shale Coalition, the Commonwealth of Pennsylvania Marcellus Shale Advisory Commission, as vice chair of the Interstate Natural Gas Association of America and chair of the Southern Gas Association. Mr. Helms received a Bachelor of Arts from Southern Illinois University at Edwardsville and a Juris Doctor from Tulane University School of Law.

Jonathan S. Linker became a director in 2002. Mr. Linker previously served as a director of Range from 1998 to 2000. He has been active in the energy industry for over 38 years. Mr. Linker joined First Reserve Corporation in 1988 and was a managing director of the firm from 1996 through 2001. Mr. Linker is currently manager of Houston Energy Advisors LLC, an investment advisor providing management and investment services to two private equity funds. Mr. Linker has been president and a director of IDC Energy Corporation since 1987, a director and officer of Sunset Production Corporation since 1991 serving currently as chairman. Mr. Linker is also on the board of Flex Energy, Inc., and a manager of Crescent Energy Services and Stonegate Production Company, LLC and a senior advisor to Och-Ziff Energy Partners. Mr. Linker received a Bachelor of Arts in Geology from Amherst College, a Masters in Geology from Harvard University and an MBA from Harvard Graduate School of Business Administration.

Mary Ralph Lowe became a director in 2013. Ms. Lowe has been president and chief executive officer of Maralo, LLC, (formerly Maralo, Inc.), an independent oil and gas exploration and production company, and ranching operation, since 1973, and a member of its board of directors since 1975. Ms. Lowe also serves on the board of trustees of Texas Christian University, the board of the Performing Arts Center of Fort Worth, the board of the National Cowgirl Museum and Hall of Fame and the board of The Modern Art Museum of Fort Worth. Ms. Lowe previously served on the board of Apache Corporation, an oil and gas exploration company.

Gregory G. Maxwell became a director in September 2015. Mr. Maxwell served as executive vice president, finance, and chief financial officer for Phillips 66, a diversified energy manufacturing and logistics company until his retirement on December 31, 2015. Mr. Maxwell has over 37 years of experience in various financial roles within the petrochemical and oil and gas industries. Mr. Maxwell served as senior vice president, chief financial officer and controller for Chevron Phillips Chemical Company from 2003 until joining Phillips 66 in 2012. He joined Phillips Petroleum Company in 1978 and held various positions within the comptrollers group including the corporate planning and development group and the corporate treasury department. Mr. Maxwell also served as vice president, chief financial officer and a member of the board of directors of Phillips 66 Partners and on the board of directors of DCP Midstream LLC and Chevron Phillips Chemical Company until his retirement in 2015. He is a certified public accountant and a certified internal auditor. He earned a Bachelor of Accountancy degree from New Mexico State

University in 1978.

Kevin S. McCarthy became a director in 2005. Mr. McCarthy is chairman, chief executive officer and president of Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Kayne Anderson Midstream/Energy Fund, Inc. and Kayne Anderson Energy Development Company, which are each NYSE listed closed-end investment companies. He also serves as co-managing partner of Kayne Anderson Capital Advisors. Mr. McCarthy joined Kayne Anderson Capital Advisors as a senior managing director in 2004 from UBS Securities LLC where he was global head of energy investment banking. In this role, he had senior responsibility for all of UBS' energy investment banking activities, including direct responsibilities for securities underwriting and mergers and acquisitions in the energy industry. From 1995 to 2000, Mr. McCarthy led the energy investment banking activities of Dean Witter Reynolds and then PaineWebber Incorporated. He began his investment banking career in 1984. He is also on the board of directors of ONEOK, Inc. He previously served on the board of Emerge Energy Services, L.P. and K-Sea Transportation Partners, L.P. He earned a Bachelor of Arts in Economics and Geology from Amherst College and an MBA in Finance from the University of Pennsylvania's Wharton School.

John H. Pinkerton, became a director in 1988 and was elected chairman of the board of directors in 2008. Mr. Pinkerton previously served as Non-Executive Chairman until January 1, 2015. He joined Range as President in 1990 and was appointed chief executive officer in 1992. Previously, Mr. Pinkerton was employed by Snyder Oil Corporation, serving in numerous capacities, the last of which was senior vice president. Mr. Pinkerton currently serves on the board of trustees of Texas Christian University. Mr. Pinkerton received his Bachelor of Arts in Business Administration from Texas Christian University and a Master's of Business Administration from the University of Texas at Arlington.

Jeffrey L. Ventura, chairman, president and chief executive officer, joined Range in 2003 as chief operating officer and became a director in 2005. Mr. Ventura was named President effective May 2008, Chief Executive Officer effective January 2012 and named chairman of the board on January 1, 2015. 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 and the Texas Society of Professional Engineers.

Roger S. Manny, executive vice president – chief financial officer. Mr. Manny joined Range in 2003. Previously, Mr. Manny served as executive vice president and chief financial officer of Matador Petroleum Corporation from 1998 until joining Range. Before 1998, Mr. Manny spent 18 years at Bank of America and its predecessors where he served as senior vice president in the energy group. Mr. Manny holds a Bachelor of Business Administration degree from the University of Houston and a Masters of Business Administration from Houston Baptist University.

Ray N. Walker, Jr., executive vice president – chief operating officer, joined Range in 2006 and was elected to his current position in January 2014. Previously, Mr. Walker served as senior vice president – chief operating officer, senior vice president-environment, safety and regulatory and senior vice president-Marcellus Shale where he led the development of the Range's Marcellus Shale division. Mr. Walker is a petroleum engineer with more than 35 years of oil and gas operations and management experience having previously been employed by Halliburton in various technical and management roles, Union Pacific Resources and several private companies in which Mr. Walker served as an officer. Mr. Walker has a Bachelor of Science degree in Agricultural Engineering from Texas A&M University.

John K. Applegath, senior vice president – Southern Marcellus Shale, joined Range in 2008 and was elected to his current position in January 2014. Mr. Applegath previously served as vice president – Southern Marcellus Shale Division. Mr. Applegath has over 38 years of industry experience with Exxon Mobil, Champlin Petroleum, Union Pacific Resources, and has served as president and chief operating officer of Basic Resources and division operations manager with Anadarko Petroleum. Mr. Applegath served our country in the United States Army as a Chief Warrant Officer II while a helicopter pilot in Vietnam. Mr. Applegath earned a Bachelor of Science degree in Chemical Engineering from the University of Houston.

Alan W. Farquharson, senior vice president – reservoir engineering & economics, joined Range in 1998. Mr. Farquharson has held the positions of manager and vice president of reservoir engineering before being promoted to senior vice president –reservoir engineering in February 2007 and his current position in January 2012 with his assumption of additional responsibilities for strategic allocation of capital. Previously, Mr. Farquharson held positions with Union Pacific Resources including engineering manager business development – international. Before that, Mr. Farquharson held various technical and managerial positions at Amoco and Hunt Oil. He holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University.

Dori A. Ginn, senior vice president – controller and principal accounting officer, joined Range in 2001 and was previously vice president, controller and principal accounting officer. 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 27 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.

Chad L. Stephens, senior vice president – corporate development, joined Range in 1990. Before 2002, Mr. Stephens held the position of Senior Vice President – Southwest. Previously, Mr. Stephens was with Duer Wagner & Co., an independent oil and gas producer, for approximately two years. Before that, Mr. Stephens was an independent oil operator in Midland, Texas for four years. From 1979 to 1984, Mr. Stephens was with Cities Service Company and HNG Oil Company. Mr. Stephens holds a Bachelor of Arts degree in Finance and Land Management from the University of Texas.

Rodney L. Waller, senior vice president and assistant secretary, joined Range in 1999. Mr. Waller served as corporate secretary from 1999 until 2008. Previously, Mr. Waller was senior vice president of Snyder Oil Corporation. Before joining Snyder, Mr. Waller was with Arthur Andersen. Mr. Waller is a certified public accountant and petroleum land man. Mr. Waller received a summa cum laude Bachelor of Arts degree in Accounting from Harding University.

Section 16(a) Beneficial Ownership Reporting Compliance

See the material appearing under the heading “Section 16(a) Beneficial Ownership Reporting Compliance” in the Range Proxy Statement for the 2016 Annual Meeting of Stockholders which is incorporated herein by reference.
Section 16(a) of the Exchange Act

requires our directors, officers (including a person performing a principal policy-making function) and persons who own more than 10% of a registered class of our equity securities to file with the SEC initial reports of ownership and reports of changes in ownership of our common stock and other equity securities. Directors, officers and 10% holders are required by SEC regulations to send us copies of all of the Section 16(a) reports they file. Based solely on a review of the copies of the forms sent to us and the representations made by the reporting persons to us, we believe that, during the fiscal year ended December 31, 2015, our directors, officers and 10% holders complied with all filing requirements under Section 16(a) of the Exchange Act., with the following exceptions: Mr. McCarthy had a delinquent Form 4 filing on May 21, 2015 for a transaction that occurred on April 24, 2015; Mr. Poole had a delinquent Form 4 filing on June 19, 2015 for a transaction that occurred on June 15, 2015 and Mr. Stephens had a delinquent Form 4 filing on May 6, 2015 for a transaction that occurred on April 30, 2015.

Code of Ethics

Code of Ethics. We have adopted a Code of Ethics that applies to our principal executive officer, principal financial officer, principal accounting officer, or persons performing similar functions (as well as our directors and all other employees). A copy is available on our website, www.rangeresources.com and a copy in print will be provided to any person without charge, upon request. Such requests should be directed to the Corporate Secretary, 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 or by calling (817) 870-2601. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our President and Chief Executive Officer, Chief Financial Officer, Controller and persons performing similar functions on our website, under the Corporate Governance caption, promptly following the date of such amendment or waiver.

Identifying and Evaluating Nominees for Directors

See “Identifying and Evaluating Nominees for Directors, including Diversity Considerations” in the Range Proxy Statement for the 2016 Annual Meeting of Stockholders, which is incorporated herein by reference.

Audit Committee

See the material under the heading “Audit Committee” in the Range Proxy Statement for the 2016 Annual Meeting of Stockholders, which is incorporated herein by reference.

NYSE 303A Certification

The President and Chief Executive Officer of Range Resources Corporation made an unqualified certification to the NYSE with respect to the Company’s compliance with the NYSE Corporate Governance listing standards on June 22, 2015.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2016 Annual Meeting of Stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2016 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2016 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2016 Annual Meeting of Stockholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of the report:

1. Financial Statements:

2. All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or related notes.

3. Exhibits:

(a) See Index of Exhibits on page 70 for a description of the exhibits filed as a part of this report.

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.

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.

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. 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.

mmcf. One million cubic feet of gas.

mmcfe. One million cubic feet of gas equivalents.

NGLs. Natural gas liquids.

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

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 an existing well bore in another formation from that in which the well has been previously completed.

reserve life. 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.

SIGNATURES

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

RANGE RESOURCES CORPORATION

By: /s/ JEFFrey L. VENTURA
Jeffrey L. Ventura
Chairman of the Board, President and

Chief Executive Officer

(principal executive officer)

Dated: February 25, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated.

Signature	Capacity	Date
/s/ Jeffrey L. Ventura Jeffrey L. Ventura	Chairman of the Board, President and Chief Executive Officer (principal executive officer)	February 25, 2016
/s/ Roger S. Manny Roger S. Manny	Executive Vice President and Chief Financial Officer (principal financial officer)	February 25, 2016
/s/ DORI A. GINN Dori A. Ginn	Senior Vice President, Controller and Principal Accounting Officer	February 25, 2016
/s/ BRENDA A. CLINE Brenda A. Cline	Director	February 25, 2016
/s/ Anthony V. Dub Anthony V. Dub	Director	February 25, 2016
/s/ V. Richard Eales V. Richard Eales	Director	February 25, 2016
	Director	February 25, 2016

/s/ ALLEN FINKELSON Allen Finkelson		
/s/ James M. Funk James M. Funk	Lead Independent Director	February 25, 2016
/s/ christopher a. helms Christopher A. Helms	Director	February 25, 2016
/s/ Jonathan S. Linker Jonathan S. Linker	Director	February 25, 2016
/s/ MARY RALPH LOWE Mary Ralph Lowe	Director	February 25, 2016
/s/ GREGORY G. MAXWELL Gregory Maxwell	Director	February 25, 2016
/s/ Kevin S. McCarthy Kevin S. McCarthy	Director	February 25, 2016
/s/ JOHN H. PINKERTON John H. Pinkerton	Director	February 25, 2016

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 to management and the Board of Directors 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. 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. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2015. In making this assessment, 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, 2015, 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, 2015. This report appears on the following page.

By:	/s/ JEFFREY L. VENTURA	By:	/s/ Roger S. Manny
	Jeffrey L. Ventura		Roger S. Manny
	Chairman, President and Chief Executive Officer		Executive Vice President and Chief Financial Officer

Fort Worth, Texas

February 25, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC

ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Board of Directors and Stockholders of

Range Resources Corporation:

We have audited Range Resources Corporation's internal control over financial reporting as of December 31, 2015, 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). Range Resources Corporation'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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

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.

In our opinion, Range Resources Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015 based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Range Resources Corporation as of December 31, 2015 and 2014 and the related consolidated statements of operations, comprehensive (loss) income, cash flows and stockholders' equity, for each of the three years in the period ended December 31, 2015 of Range Resources Corporation and our report dated February 25, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas

February 25, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders of

Range Resources Corporation:

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the “Company”) as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive (loss) income, cash flows and stockholders’ equity for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Range Resources Corporation at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, 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), Range Resources Corporation’s internal control over financial reporting as of December 31, 2015, 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, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Fort Worth, Texas

February 25, 2016

RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31, 2015	2014
Assets		
Current assets:		
Cash and cash equivalents	$471	$448
Accounts receivable, less allowance for doubtful accounts of $4,994 and $2,719	123,842	188,941
Derivative assets	281,544	363,049
Inventory and other	33,217	17,854
Total current assets	439,074	570,292
Derivative assets	7,218	40,314
Natural gas and oil properties, successful efforts method	8,996,336	10,567,971
Accumulated depletion and depreciation	(2,635,031)	(2,590,398)
	6,361,305	7,977,573
Other property and equipment	110,013	127,808
Accumulated depreciation and amortization	(90,558)	(90,227)
	19,455	37,581
Other assets	72,979	78,844
Total assets	$6,900,031	$8,704,604
Liabilities		
Current liabilities:		
Accounts payable	$117,346	$396,942
Asset retirement obligations	15,071	15,067
Accrued liabilities	188,028	187,973
Accrued interest	30,139	39,695
Derivative liabilities	1,136	—
Total current liabilities	351,720	639,677
Bank debt	86,427	713,221
Senior notes	738,101	—
Senior subordinated notes	1,826,775	2,317,603
Deferred tax liabilities	777,947	1,113,081
Derivative liabilities	21	—
Deferred compensation liabilities	104,792	178,599
Asset retirement obligations and other liabilities	254,590	284,994
Total liabilities	4,140,373	5,247,175
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, 169,375,743 issued at December 31, 2015 and 168,711,131 issued at December 31, 2014	1,693	1,687

Common stock held in treasury, 59,283 shares at December 31, 2015 and 82,954 shares at December 31, 2014	(2,245)	(3,088)
Additional paid-in capital	2,442,623	2,400,475
Retained earnings	317,587	1,058,355
Total stockholders' equity	2,759,658	3,457,429
Total liabilities and stockholders' equity	$6,900,031	$8,704,604

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF operations

(In thousands, except per share data)

	Year Ended December 31,		
	2015	2014	2013
Revenues and other income:			
Natural gas, NGLs and oil sales	$1,089,644	$1,911,989	$1,715,676
Derivative fair value income (loss)	416,364	383,520	(61,825)
Brokered natural gas, marketing and other	92,060	130,548	116,577
Total revenues and other income	1,598,068	2,426,057	1,770,428
Costs and expenses:			
Direct operating	136,363	150,483	128,091
Transportation, gathering and compression	396,739	325,289	256,242
Production and ad valorem taxes	33,860	44,555	45,240
Brokered natural gas and marketing	115,866	129,980	131,786
Exploration	21,406	63,548	64,409
Abandonment and impairment of unproved properties	47,619	47,079	51,918
General and administrative	194,015	213,426	291,171
Termination costs	15,070	8,371	—
Deferred compensation plan	(77,627)	(74,550)	55,296
Interest	166,439	168,977	176,557
Loss on early extinguishment of debt	22,495	24,596	12,280
Depletion, depreciation and amortization	581,155	551,032	492,397
Impairment of proved properties and other assets	590,174	28,024	7,753
Loss (gain) on the sale of assets	406,856	(285,638)	(92,291)
Total costs and expenses	2,650,430	1,395,172	1,620,849
(Loss) income before income taxes	(1,052,362)	1,030,885	149,579
Income tax (benefit) expense:			
Current	29	1	(143)
Deferred	(338,706)	396,502	34,000
	(338,677)	396,503	33,857
Net (loss) income	$(713,685)	$634,382	$115,722
Net (loss) income per common share:			
Basic	$(4.29)	$3.81	$0.71
Diluted	$(4.29)	$3.79	$0.70
Weighted average common shares outstanding:			
Basic	166,389	163,625	160,438
Diluted	166,389	164,403	161,407

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

(In thousands)

	December 31,		
	2015	2014	2013
Net (loss) income	$(713,685)	$634,382	$115,722
Other comprehensive income:			
Realized gain on hedge derivative contract settlements reclassified into natural gas, NGLs and oil sales from other comprehensive income, net of taxes [1]	—	—	(14,840)
De-designated hedges reclassified into natural gas, NGLs and oil sales, net of taxes [2]	—	(6,236)	(56,254)
De-designated hedges reclassified to derivative fair value, net of taxes [3]	—	—	(2,376)
Change in unrealized deferred hedging losses, net of taxes [4]	—	—	(4,203)
Total comprehensive (loss) income [5]	$(713,685)	$628,146	$38,049

(1) Amounts are net of income tax benefit of $9,488 for the year ended December 31, 2013.

(2) Amounts are net of income tax benefit of $3,986 for the year ended December 31, 2014 compared to $35,968 for the year ended December 31, 2013.

(3) Amounts relate to transactions not probable of occurring and are presented net of income tax benefit of $1,517 for the year ended December 31, 2013.

(4) Amounts are net of income tax benefit of $2,687 for the year ended December 31, 2013.

(5) As of March 31, 2013, we elected to discontinue hedge accounting prospectively, and as of December 31, 2014, all remaining accumulated other comprehensive income had been transferred to earnings.

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2015	2014	2013
Operating activities:			
Net (loss) income	$(713,685)	$634,382	$115,722
Adjustments to reconcile net (loss) income to net cash provided from operating activities:			
Loss (gain) from equity method investments, net of distributions	—	3,095	(2,973)
Deferred income tax (benefit) expense	(338,706)	396,502	34,000
Depletion, depreciation and amortization and impairment	1,171,329	579,056	500,150
Exploration dry hole and impairment costs	88	16,145	5,699
Abandonment and impairment of unproved properties	47,619	47,079	51,918
Derivative fair value (income) loss	(416,364)	(383,520)	61,825
Cash settlements on derivative financial instruments that do not qualify for hedge accounting	532,122	(42,634)	(31,256)
Allowance for bad debt	2,300	250	250
Amortization of deferred financing costs, loss on extinguishment of debt and other	29,383	24,694	23,866
Deferred and stock-based compensation	(20,411)	(4,295)	119,398
Loss (gain) on the sale of assets	406,856	(285,638)	(92,291)
Changes in working capital:			
Accounts receivable	64,704	(5,329)	(21,212)
Inventory and other	(14,868)	(4,521)	3,785
Accounts payable	(26,197)	(1,023)	(13,555)
Accrued liabilities and other	(40,470)	(20,108)	(11,788)
Net cash provided from operating activities	683,700	954,135	743,538
Investing activities:			
Additions to natural gas and oil properties	(1,030,644)	(1,200,419)	(1,159,252)
Additions to field service assets	(4,441)	(11,863)	(5,925)
Acreage purchases	(74,880)	(211,971)	(132,145)
Other	(75)	1,103	3,799
Proceeds from disposal of assets	890,901	180,508	315,522
Purchases of marketable securities held by the deferred compensation plan	(28,876)	(30,898)	(36,136)
Proceeds from the sales of marketable securities held by the deferred compensation plan	29,243	28,084	30,701
Net cash used in investing activities	(218,772)	(1,245,456)	(983,436)
Financing activities:			
Borrowings on credit facilities	2,271,000	2,107,000	1,684,000
Repayments on credit facilities	(2,899,000)	(1,884,000)	(1,923,000)
Issuance of senior or senior subordinated notes	750,000	—	750,000

Repayment of senior subordinated notes	(516,875)	(312,000)	(259,063)
Dividends paid	(27,083)	(26,610)	(26,129)
Debt issuance costs	(14,156)	(8,866)	(12,448)
Issuance of common stock	—	396,562	343
Change in cash overdrafts	(37,089)	3,371	5,610
Proceeds from the sales of common stock held by the deferred compensation plan	8,298	15,964	20,681
Net cash (used in) provided from financing activities	(464,905)	291,421	239,994
Increase in cash and cash equivalents	23	100	96
Cash and cash equivalents at beginning of year	448	348	252
Cash and cash equivalents at end of year	$471	$448	$348

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands, except per share data)

	Common stock		Common stock held in	Additional paid-	Retained	Accumulated other comprehensive	
	Shares	Par value	treasury	in capital	earnings	income (loss)	Total
Balance as of December 31, 2012	162,642	$ 1,626	$ (4,760)	$ 1,915,627	$ 360,990	$ 83,909	$ 2,357,392
Issuance of common stock	799	8	—	9,281	—	—	9,289
Stock-based compensation expense	—	—	—	35,851	—	—	35,851
Common dividends declared ($0.16 per share)	—	—	—	—	(26,129)	—	(26,129)
Treasury stock issuance	—	—	1,123	(1,123)	—	—	—
Other comprehensive loss	—	—	—	—	—	(77,673)	(77,673)
Net income	—	—	—	—	115,722	—	115,722
Balance as of December 31, 2013	163,441	1,634	(3,637)	1,959,636	450,583	6,236	2,414,452
Issuance of common stock	5,270	53	—	398,554	—	—	398,607
Stock-based compensation expense	—	—	—	42,834	—	—	42,834
Common dividends declared ($0.16 per share)	—	—	—	—	(26,610)	—	(26,610)
Treasury stock issuance	—	—	549	(549)	—	—	—
Other comprehensive loss	—	—	—	—	—	(6,236)	(6,236)
Net income	—	—	—	—	634,382	—	634,382
Balance as of December 31, 2014	168,711	1,687	(3,088)	2,400,475	1,058,355	—	3,457,429
Issuance of common stock	665	6	—	10,067	—	—	10,073
Stock-based compensation	—	—	—	36,496	—	—	36,496

expense							
Tax benefit related to stock-based compensation	—	—	—	(3,572)	—	—	(3,572)
Common dividends declared ($0.16 per share)	—	—	—	—	(27,083)	—	(27,083)
Treasury stock issuance	—	—	843	(843)	—	—	—
Net loss	—	—	—	—	(713,685)	—	(713,685)
Balance as of December 31, 2015	169,376	$ 1,693	$ (2,245)	$ 2,442,623	$ 317,587	$ —	$ 2,759,658

See accompanying notes.

RANGE RESOURCES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Organization and Nature of Business

Range Resources Corporation ("Range," "we," "us," or "our") is a Fort Worth, Texas-based independent natural gas, NGLs and oil company primarily engaged in the exploration, development and acquisition of natural gas and oil properties in the Appalachian region of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Range is a Delaware corporation with our common stock listed and traded on the New York Stock Exchange under the symbol "RRC."

(2) Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of all of our subsidiaries. Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting and are carried at our share of net assets plus loans and advances. Income from equity method investments represents our proportionate share of income generated by equity method investees and is included in brokered natural gas, marketing and other revenues in the accompanying consolidated statements of operations. As of June 2014, we no longer have equity method investments. All material intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates and changes in these estimates are recorded when known.

Reclassifications

Certain reclassifications have been made to prior years' reported amounts in order to conform to the current year presentation. This includes reclassification of deferred income tax balances included in the consolidated balance sheets from current to long-term and the reclassification of debt issuance costs included in the consolidated balance sheets from other assets to offset our debt balances. These reclassifications were made as a result of our adoption of new accounting pronouncements and did not impact our net loss, stockholders' equity or cash flows.

Business Segment Information

We have evaluated how we are organized and managed and have identified only one operating segment, which is the exploration and production of natural gas, NGLs and oil in the United States. We consider our gathering, processing and marketing functions as integral to our natural gas and oil producing activities. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and this information is regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

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 a geographical or area-by-area basis. Throughout the year, we allocate capital resources on a project-by-project basis, across our entire asset base to maximize profitability without regard to individual areas.

Revenue Recognition, Accounts Receivable and Gas Imbalances

Natural gas, NGLs and oil sales are recognized when we deliver our production to the customer and collectability is reasonably assured. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. We are reporting our gathering and transportation costs in accordance with Accounting Standards Code Section 605-45-05 of Subtopic 605-45 for Revenue Recognition. One type of agreement is a netback arrangement, under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the price we receive from the purchaser. For the sale of our NGLs, we receive a price from the purchaser (which is net of processing costs) that is recorded in revenue at the net price we receive. Under the other type of agreement, we sell natural gas or oil at a specific delivery point, pay transportation, gathering and compression expenses to a third party and receive proceeds from the purchaser with no deduction. In that case, we record revenue at the price received from the purchaser and record the expenses we incur as transportation, gathering and compression expense.

We realize brokered margins as a result of buying and selling natural gas utilizing separate purchase and sale transactions, typically with separate counterparties, whereby Range or the counterparty takes titles to the natural gas purchased or sold. Revenues and expenses related to brokering natural gas are reported gross as part of revenues and expenses in accordance with applicable accounting standards. In 2013, we also included purchased (and sold) natural gas which was used to blend our rich residue gas from the Southwest Marcellus Shale. In 2014, we also included additional broker revenues and broker expenses from the release of transportation capacity where we had taken firm transportation ahead of our production volumes. Our net brokered margin was a loss of $2.7 million in 2015 compared to a gain of $9.4 million in 2014 and a loss of $5.7 million in 2013.

Although receivables are concentrated in the oil and gas industry, we do not view this as an unusual credit risk. We provide for an allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, our experience with the debtor, potential offsets to the amount owed and economic conditions. In certain instances, we require purchasers to post stand-by letters of credit. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We have allowances for doubtful accounts relating to exploration and production receivables of $5.0 million at December 31, 2015 compared to $2.7 million at December 31, 2014. We recorded bad debt expense of $2.3 million in the year ended December 31, 2015 compared to $250,000 in both the years ended December 31, 2014 and 2013.

Revenues from the production of natural gas, NGLs and oil on properties in which we have joint ownership are recorded under the sales method. Under the sales method, we and other joint owners may sell more or less than our entitled share of production. Should our sales exceed our share of remaining reasonable reserves, a liability is recorded. Imbalances are not significant in the periods presented.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less. Outstanding checks in excess of funds on deposit are included in accounts payable on the consolidated balance sheets and the change in such overdrafts are classified as financing activities on the consolidated statements of cash flows.

Marketable Securities

Investments in unaffiliated equity securities held in our deferred compensation plans qualify as trading securities and are recorded at fair value. Investments held in the deferred compensation plans consist of various publicly-traded mutual funds. These funds include equity securities and money market instruments.

Inventory

Inventories were comprised of $20.8 million of materials and supplies at December 31, 2015 compared to $11.8 million at December 31, 2014. Inventories consist primarily of tubular goods and equipment used in our operations and are stated at the lower of specific cost of each inventory item or market, on a first-in, first-out basis. Our material and supplies inventory is primarily acquired for use in future drilling operations or repair operations. At December 31, 2015, we also had commodity inventory of $4.8 million, compared to $2.0 million at December 31, 2014, which is carried at lower of average cost or market, on a first-in, first-out basis. Commodity inventory at December 31, 2015 consists of natural gas and NGLs held in storage or as line fill in pipelines.

Natural Gas and Oil Properties

Property Acquisition Costs. We use the successful efforts method of accounting for natural gas and oil producing activities. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, delay rentals and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed not less than quarterly. We capitalize successful exploratory wells and all developmental wells, whether successful or not. Due to the capital-intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather our ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production data in the area, transportation or processing facilities and/or obtaining partner approval to drill additional appraisal wells. These activities are ongoing and are being pursued constantly. Consequently, our assessment of suspended exploratory well costs is continuous until a decision can be made that the project has found proved reserves to sanction the project or is noncommercial and is charged to exploration expense. For more information regarding suspended exploratory well costs, see Note 6.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of proved producing properties, including other property and equipment such as gathering lines related to natural gas and oil producing activities, is provided on the units of production method. Historically, we have adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and at other times during the year when circumstances indicate there has been a significant change in reserves or costs.

Impairments. Our proved natural gas and oil properties are reviewed for impairment annually and periodically as events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. These assets are reviewed for potential impairment at the lowest level 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 expected undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop reserves. Expected future net cash inflow from the sale of produced reserves is calculated based on estimated future prices and estimated operating and development costs. 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 climate. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of cash flows. When the carrying value exceeds the sum of undiscounted 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. 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 and oil prices, an estimate of the ultimate amount of recoverable natural gas and oil reserves that will be produced from an asset group, the timing of future production, future production costs, future abandonment costs and future inflation. We cannot predict whether impairment charges may be required in the future. If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record additional impairments. For additional information regarding proved property impairments, see Note 11.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leasehold costs. 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. Impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors. Unproved properties had a net book value of $949.2 million as of December 31, 2015 compared to $943.2 million in 2014. We have recorded abandonment and impairment expense related to unproved properties of $47.6 million in the year ended December 31, 2015 compared to $47.1 million in 2014 and $51.9 million in 2013.

Dispositions. Proceeds from the disposal of natural gas and oil producing properties that are part of an amortization base are credited to the net book value of the amortization group with no immediate effect on income. However, gain or loss is recognized if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base. For additional information regarding our dispositions, see Note 3.

Acquisitions. Acquisitions of proved properties are accounted for as business combinations and, accordingly, the results of operations are included in the accompanying consolidated statements of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets and assumed liabilities based on their estimated fair value at the time of the acquisition. In the past, acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities.

Other Property and Equipment

Other property and equipment includes assets such as buildings, furniture and fixtures, field equipment, leasehold improvements and data processing and communication equipment. These items are generally depreciated by individual components on a straight-line basis over their economic useful life, which is generally from three to ten years. Leasehold improvements are amortized over the lesser of their economic useful lives or the underlying terms of the associated leases. Depreciation expense was $11.9 million in the year ended December 31, 2015 compared to $12.9 million in the year ended December 31, 2014 and $13.2 million in the year ended December 31, 2013.

Other Assets

Other assets at December 31, 2015 include $62.4 million of marketable securities held in our deferred compensation plans and $10.6 million of other investments including surface acreage. Other assets at December 31, 2014 include $68.5 million of marketable securities held in our deferred compensation plans and $10.3 million of other investments including surface acreage.

Stock-based Compensation Arrangements

The fair value of performance share unit awards ("PSUs") 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 stock-settled stock appreciation rights ("SARs") is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The models employ various assumptions, based on management's best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the awards. We have utilized historical data and analyzed current information to reasonably support these assumptions. The fair value of restricted stock awards ("Liability Awards") and restricted stock unit awards ("Equity Awards") 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. The majority of our Liability Awards are deposited in our deferred compensation plan at the time of grant and are classified as a liability due to the fact that these awards are expected to be settled wholly or partially in cash. The fair value of the Liability Awards is updated at each balance sheet date with changes in the fair value of the vested portion of the awards recorded as increases or decreases to deferred compensation plan expense in the accompanying consolidated statements of operations.

Derivative Financial Instruments and Hedging

All of our derivative instruments are issued to manage the price risk attributable to our expected natural gas, NGLs and oil production. While there is 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 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 capital markets. All unsettled derivative instruments are recorded in the accompanying consolidated balance sheets as either an asset or a liability measured at their fair value. In most cases, our derivatives are reflected on our consolidated balance sheets on a net basis by brokerage firm, when they are governed by master netting agreements. Changes in a derivative's fair value are recognized in earnings unless specific hedge accounting criteria are met. Cash flows from derivative contract settlements are reflected in operating activities in the accompanying consolidated statements of cash flows.

Effective March 1, 2013, we elected to discontinue hedge accounting prospectively. For more information, see Note 10. The effective portions of the discontinued deferred hedges as of March 1, 2013 were included in accumulated other comprehensive income ("AOCI") and were transferred to earnings during the same periods in which the forecasted transactions were recognized in earnings. During 2014, the remaining AOCI hedging gains were transferred to earnings. Since discontinuing hedge accounting, all realized and unrealized gains and losses on derivatives are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts in each period in derivative fair value in the accompanying consolidated statements of operations. At times, we have also entered into 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 natural gas basis swap agreements that effectively fix our basis adjustments. We have also entered into propane basis swaps which lock in the differential between Mont Belvieu and international propane indexes.

From time to time, we may enter into derivative contracts and pay or receive premium payments at the inception of the derivative contract which represent the fair value of the contract at its inception. These amounts would be included within the net derivative asset or liability on our consolidated balance sheets. The amounts paid or received for derivative premiums reduce or increase the amount of gains and losses that are recorded in the earnings each period as the derivative contracts settle. We have not acquired any hedges through a business combination and have not modified any existing derivative contracts.

Concentrations of Credit Risk

As of December 31, 2015, our primary concentrations of credit risk are the risks of collecting accounts receivable and the risk of counterparties' failure to perform under derivative contracts. Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions, commodity traders and end-users in various industries and are generally unsecured. To manage risks of collecting accounts receivable, we monitor our counterparties financial strength and/or credit ratings and where we deem necessary, obtain parent company guarantees, prepayments, letters of credit or other credit enhancements to reduce risk of loss. Our allowance for doubtful accounts was $5.0 million at December 31, 2015 compared to $2.7 million at December 31, 2014.

For the year ended December 31, 2015, we had one customer that accounted for 10% or more of total natural gas, NGLs and oil sales. For both of the years ended December 31, 2014 and December 31, 2013, we had four customers that accounted for 10% or more of total natural gas, NGLs and oil sales. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, NGLs and oil production.

We have executed International Swap Dealers Association Master Agreements ("ISDA Agreements") with counterparties for the purpose of entering into derivative contracts. To manage counterparty risk associated with our derivatives, we select and monitor counterparties based on assessment of their financial strength and/or credit ratings. We may also limit the level of exposure with any single counterparty. Additionally, the terms of our ISDA Agreements provide us and our counterparties with netting rights such that we may offset payables against receivables with a counterparty under separate derivative contracts. Our ISDA Agreements also generally contain set-off rights such that, upon the occurrence of defined acts of default by either us or a counterparty to a derivative contract, the non-defaulting party may set off receivables owed under all derivative contracts against payables from other agreements with that counterparty. None of our derivative contracts have margin requirements or collateral provisions that would require us to fund or post additional collateral prior to the scheduled cash settlement date.

At December 31, 2015, our derivative counterparties included seventeen financial institutions and commodity traders of which all but four are secured lenders in our bank credit facility. At December 31, 2015, our net derivative asset includes a receivable from the counterparties not included in our bank credit facility totaling $11.5 million. In determining fair value of derivative assets, we evaluate the risk of non-performance and incorporate factors such as amounts owed under other agreements permitting set off, as well as pricing of credit default swaps for the counterparty. Net derivative liabilities are determined in part by using our market based credit spread to incorporate our theoretical risk of non-performance.

Asset Retirement Obligations

The fair value of asset retirement obligations is recognized in the period they are incurred, if a reasonable estimate of fair value can be made. Asset retirement obligations primarily relate to the abandonment of natural gas and oil producing facilities and include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures. Estimates are based on historical experience of plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates of the cost to plug and abandon the wells in the future and federal and state regulatory requirements. We are required to operate and maintain our natural gas pipeline systems and intend to do so as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, these assets have indeterminate lives. Depreciation of capitalized asset retirement costs will generally be determined on a units-of-production basis while accretion to be recognized will escalate over the life of the producing assets. See Note 8 for additional information.

Environmental Costs

Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. Expenditures that relate to an existing condition caused by past operations that have no future economic benefits are expensed.

Deferred Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. Deferred tax assets are recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors may include our expectation to generate sufficient taxable income in the periods before tax credits and operating loss carryforwards expire. We do not recognize a deferred tax asset for excess tax benefits on equity compensation that have not been realized due to our net operating loss tax position for federal or state tax purposes. All deferred taxes are classified as long-term on the balance sheet.

Accumulated Other Comprehensive Income

The following details the components of AOCI and related tax effects for the two years ended December 31, 2014 (in thousands). Amounts included in AOCI exclusively relate to our derivative activity. See Note 10 for additional information on the discontinuance of hedge accounting.

	Gross	Tax Effect	Net of Tax
Accumulated other comprehensive income at December 31, 2012	$137,555	$(53,646)	$83,909
Contract settlements reclassified to income	(120,443)	46,973	(73,470)
Change in unrealized deferred hedging gains	(6,890)	2,687	(4,203)
Accumulated other comprehensive income at December 31, 2013	10,222	(3,986)	6,236
Contract settlements reclassified to income	(10,222)	3,986	(6,236)
Accumulated other comprehensive income at December 31, 2014	$¾	$¾	$¾

New Accounting Pronouncements

Recently Adopted

In April 2014, an accounting standards update was issued that raised the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other material disposal transactions that do not meet the revised definition of a discontinued operation. Under the updated standard, a disposal of a component or group of components of an entity is required to be reported as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component or group of components of the entity (1) has been disposed of by a sale, (2) has been disposed of other than by sale or (3) is classified as held for sale. This accounting standards update is effective for annual periods beginning on or after December 15, 2014 and is applied prospectively. Early adoption was permitted but only for disposals (or classifications that are held for sale) that had not been reported in financial statements previously issued or available for use. We adopted this new standard in first quarter 2014 and, as a result, the Conger Exchange defined and described in more detail below, was not reported as a discontinued operation.

In April 2015, an accounting standards update was issued that requires debt issuance costs to be presented in the balance sheet as a direct reduction from the associated debt liability. This standard is effective for the reporting period beginning on January 1, 2016 with early adoption permitted. As of December 31, 2015, we have adopted this standard retrospectively and have accounted for the debt issuance costs as a reduction of the associated debt liability. Previously, these costs were reported in other long-term assets. We reclassified $9.8 million from other long-term assets to bank debt and $32.4 million from other long-term assets to subordinated notes as of December 31, 2014. This adoption only affected our consolidated balance sheet and did not have an impact on our consolidated results of operations or cash flows.

In November 2015, an accounting standards update was issued which requires entities to classify all deferred tax assets and liabilities as noncurrent on the balance sheet instead of separating deferred taxes into current and noncurrent amounts. This standard is effective for the reporting period beginning in January 1, 2017 with early adoption permitted. As of December 31, 2015, we have adopted this standard retrospectively and have reclassified our December 31, 2014 current deferred tax assets and liabilities into non-current deferred tax assets and liabilities. We reclassified $115.6 million current deferred tax liabilities into non-current deferred tax liabilities as of December 31, 2014. This adoption only affected our consolidated balance sheets and did not have an impact on our consolidated results of operations or cash flows.

Accounting Pronouncements Not Yet Adopted

In May 2014, an accounting standards update was issued that supersedes the existing revenue recognition requirements. This standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. Among other things, the standard also eliminates industry-specific revenue guidance, requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively and improves guidance for multiple-element arrangements. This standard is effective for us in first quarter 2018 and should be applied retrospectively to each prior reporting period presented or with the cumulative effect of initially applying the update recognized at the date of initial application. Early adoption is permitted with an effective date no earlier than first quarter 2017. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our consolidated results of operations, financial position or cash flows.

In August 2014, an accounting standards update was issued that requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in United States auditing standards. This standard is effective for us in first quarter 2017 and early adoption is permitted. We do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

(3) Acquisitions and Dispositions

We recognized a pretax net loss on the sale of assets of $406.9 million in the year ended December 31, 2015 compared to a gain of $285.6 million in 2014 and a gain of $92.3 million in 2013. The following describes the significant divestitures that are included in our consolidated results of operations for each of three years ended December 31, 2015, 2014 and 2013.

2015 Dispositions

Virginia and West Virginia. In December 2015, we sold the majority of our producing properties and gathering assets in Virginia and West Virginia for cash proceeds of $876.0 million, before closing adjustments. We recorded a pretax loss of $407.7 million related to this sale. We recognized $52.3 million of field net operating income (defined as natural gas, oil and NGLs sales plus net brokered margin less direct operating expenses, production and ad valorem taxes, transportation expense, exploration expense and divisional office general and administrative expense) for these assets for the period from January 1, 2015 to December 30, 2015 compared to $98.3 million in the year ended December 31, 2014 and $46.1 million in the year ended December 31, 2013.

West Texas. In February 2015, we sold certain of our West Texas properties for cash proceeds of $10.5 million and we recognized a pretax loss of $101,000.

Other. During 2015, we also sold miscellaneous inventory, surface acreage and unproved property for proceeds of $4.4 million and recorded a gain of $943,000.

2014 Dispositions

Conger Exchange Transaction. In April 2014, we entered into an exchange agreement with EQT Corporation and certain of its affiliates (collectively, "EQT") in which we sold our Conger assets in Glasscock and Sterling Counties, Texas in exchange for producing properties and gas gathering assets in Virginia and $145.0 million in cash, before closing adjustments ("the Conger Exchange"). We closed the exchange transaction in June 2014 and recognized a pretax gain of $272.7 million, after selling expenses of $5.0 million, which is recognized as a gain on sale of assets in our consolidated statements of operations for the year ended December 31, 2014. For the period from January 1, 2014 through June 16, 2014, we recognized $21.9 million of field net operating income (defined as natural gas, oil and NGLs sales plus net brokered margin less direct operating expenses, production and ad valorem taxes and transportation expenses) for our Conger assets compared to $48.7 million for the year ended December 31, 2013.

In connection with the Conger Exchange, we acquired the remaining 50% interest held by EQT in Nora Gathering, LLC ("NGLLC"), a natural gas gathering operation, which we had previously accounted for using the equity method of accounting. As of June 2014, we consolidated NGLLC into our consolidated financial statements. Our previous 50% membership interest in NGLLC was remeasured to fair value of $134.8 million on the acquisition date, resulting in a gain of $10.0 million which is recognized in gain on sale of assets in our consolidated statements of operations for the year ended December 31, 2014.

For the period from June 16, 2014 through December 31, 2014, we recognized $33.8 million of natural gas, oil and NGLs sales from the property interests acquired in the Conger Exchange and we recognized $25.7 million of field net operating income from the property interests acquired in the Conger Exchange.

Conger Exchange Fair Value. Accounting standards define fair value as 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 (often referred to as the "exit price"). The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The fair value of the Conger Exchange described above was based on an income approach which was supplemented by a market approach. For the natural gas and oil properties, the income approach uses significant inputs not observable in the market, which are Level 3 inputs. The significant inputs assumed include future production, costs and capital, commodity prices, risk-adjusted discount rates, natural gas and oil pricing differentials, and projected reserve recovery factors. The market approach uses inputs such as recent market transactions in a similar geographic region and with similar production. The income approach for the natural gas gathering operations was based on a discounted future net cash flow model, which uses Level 3 inputs and was supplemented by a market approach.

Other. During 2014, we also sold miscellaneous proved and unproved oil and gas properties, inventory and other property and equipment for proceeds of $35.5 million and recognized a pretax gain of $3.0 million.

2013 Dispositions

Southeast New Mexico and West Texas. In April 2013, we completed the sale of our Delaware and Permian Basin properties in Southeast New Mexico and West Texas for a price of $275.0 million and we recognized a pretax gain of $83.3 million, before selling expenses of $4.2 million.

Other. During 2013, we also sold miscellaneous proved and unproved oil and gas properties, inventory, and other property and equipment for proceeds of $40.5 million and recorded a pretax gain of $13.2 million.

(4) Income Taxes

Our income tax benefit was $338.7 million for the year ended December 31, 2015 compared to income tax expense of $396.5 million in 2014 and income tax expense of $33.9 million in 2013. Reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2015	2014	2013
Federal statutory tax rate	35.0 %	35.0 %	35.0 %
State	4.3	3.1	(2.3)
State apportionment rate change	(0.2)	(0.2)	(14.9)
Non-deductible executive compensation	(0.1)	0.2	0.7
Valuation allowances	(6.8)	0.2	3.5
Other	¾	0.2	0.6
Consolidated effective tax rate	32.2 %	38.5 %	22.6 %

Income tax (benefit) expense attributable to income before income taxes consists of the following (in thousands):

	2015			2014			2013		
	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
U.S. federal	$¾	$(328,257)	$(328,257)	$ ¾	$361,152	$361,152	$¾	$58,527	$58,527
U.S. state and local	29	(10,449)	(10,420)	1	35,350	35,351	(143)	(24,527)	(24,670)
Total	$29	$(338,706)	$(338,677)	$ 1	$396,502	$396,503	$(143)	$34,000	$33,857

Significant components of deferred tax assets and liabilities are as follows:

	December 31, 2015	2014
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforward	$173,503	$176,812
Deferred compensation	45,413	73,942
Equity compensation	25,940	25,833
AMT credits and other credits	4,437	4,447
Asset retirement obligation	101,142	109,808
Cumulative mark-to-market loss	¾	649
Other	10,163	10,908
Valuation allowances:		
Federal	(42,500)	¾
State, net of federal benefit	(41,516)	(8,800)
Deferred compensation plans and other	(3,607)	(7,799)
Total deferred tax assets	272,975	385,800
Deferred tax liabilities:		
Depreciation, depletion and investments	(940,482)	(1,342,038)
Cumulative mark-to-market gain	(109,845)	(154,183)
Other	(595)	(2,660)
Total deferred tax liabilities	(1,050,922)	(1,498,881)
Net deferred tax liability	$(777,947)	$(1,113,081)

At December 31, 2015, deferred tax liabilities exceeded deferred tax assets by $777.9 million. As of December 31, 2015, we have a valuation allowance of $3.1 million on the deferred tax asset related to our deferred compensation plan for planned future distributions to certain executives to the extent that their estimated future compensation plus distribution amounts would exceed the $1.0 million deductible limit provided under I.R.C. Section 162(m). During 2015, we adjusted our state net operating loss and credit carryforwards by a total of $32.7 million. This amount includes $15.6 million in net operating loss carryforwards for Louisiana, Mississippi, Oklahoma and West Virginia and establishes a full valuation for these states where we do not expect to generate any taxable income in the future due to completed or anticipated sales. We established a valuation allowance in 2015 related to our Pennsylvania net operating loss carryforwards of $16.0 million due to the low commodity price environment and the limitation Pennsylvania places on future utilization of net operating loss carryforwards. We also recorded a $1.0 million valuation allowance related to our Texas Margin Tax credit carryforward. In addition, during 2015 we have recorded a valuation allowance of $42.5 million related to our federal net operating loss carryforwards which we expect will expire unused based exclusively on our estimated turn of temporary difference in the next four years.

At December 31, 2015, we had regular net operating loss (“NOL”) carryforwards of $620.6 million and alternative minimum tax (“AMT”) NOL carryforwards of $539.3 million that expire between 2018 and 2035. Our federal deferred tax asset related to regular NOL carryforwards at December 31, 2015 was $123.5 million, which is net of the Accounting Standards Codification 718, “Stock Compensation” reduction for unrealized benefits, related to NOL’s created by excess tax deductions that have not generated current tax benefits. At December 31, 2015, we have AMT credit carryforwards of $665,000 that are not subject to limitation or expiration.

We file consolidated tax returns in the United States federal jurisdiction. We file separate company state income tax returns in Louisiana, Mississippi, Pennsylvania and Virginia and file consolidated or unitary state income tax returns in Oklahoma, Texas and West Virginia. We are subject to U.S. Federal income tax examinations for the years 2012 and after and we are subject to various state tax examinations for years 2011 and after. We have not extended the statute of limitation period in any income tax jurisdiction. Our policy is to recognize interest related to income tax expense in interest expense and penalties in general and administrative expense. We do not have any accrued interest or penalties related to tax amounts as of December 31, 2015. Throughout 2015, our unrecognized tax benefits were not material.

(5) Net (Loss) Income per Common Share

Basic income or loss per share attributable to common stockholders is computed as (i) income or loss attributable to common stockholders (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. Diluted income or loss per share attributable to common stockholders is computed as (i) basic income or loss attributable to common stockholders (ii) plus diluted adjustments to income allocable to participating securities (iii) divided by weighted average diluted shares outstanding. The following table sets forth a reconciliation of net income or loss to basic income or loss attributable to common stockholders and to diluted income or loss attributable to common stockholders (in thousands except per share amounts):

	Year Ended December 31,		
	2015	2014	2013
Net (loss) income, as reported	$(713,685)	$634,382	$115,722
Participating basic earnings [a]	(450)	(10,725)	(1,975)
Basic net (loss) income attributed to common stockholders	(714,135)	623,657	113,747
Reallocation of participating earnings [a]	¾	48	9
Diluted net (loss) income attributed to common stockholders	$(714,135)	$623,705	$113,756
Net (loss) income per common share:			
Basic	$(4.29)	$3.81	$0.71
Diluted	$(4.29)	$3.79	$0.70

[a] Restricted stock Liability Awards represent participating securities because they participate in nonforfeitable dividends or distributions with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Participating securities, however, do not participate in undistributed net losses.

The following table provides a reconciliation of basic weighted average common shares outstanding to diluted weighted average common shares outstanding (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Denominator:			
Weighted average common shares outstanding – basic	166,389	163,625	160,438
Effect of dilutive securities:			
Director and employee SARs and restricted stock Equity Awards	¾	778	969
Weighted average common shares outstanding – diluted	166,389	164,403	161,407

Weighted average common shares – basic excludes 2.8 million shares of restricted stock Liability Awards held in our deferred compensation plans (although all awards are issued and outstanding upon grant) for all of the periods ending December 31, 2015, December 31, 2014 and December 31, 2013. Due to our net loss for the year ended December 31, 2015, we excluded all outstanding stock appreciation rights and restricted stock from the computation of diluted net loss per share because the effect would have been anti-dilutive to the computations. SARs of 1,900 for the year ended December 31, 2014 compared to 226,000 in 2013 were outstanding but not included in the computations of diluted net income per share because the grant prices of the SARs were greater than the average market price of the common shares and would be anti-dilutive to the computations.

(6) Suspended Exploratory Well Costs

We capitalize exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. Capitalized exploratory well costs are presented in natural gas and oil properties in the accompanying consolidated balance sheets. If an exploratory well is determined to be impaired, the well costs are charged to exploration expense in the accompanying consolidated statements of operations. The following table reflects the changes in capitalized exploratory well costs for the years ended December 31, 2015, 2014 and 2013 (in thousands, except for number of projects):

	2015	2014	2013
Balance at beginning of period	$2,996	$6,964	$57,360
Additions to capitalized exploratory well costs pending the determination of proved reserves	1,165	18,747	39,832
Reclassifications to wells, facilities and equipment based on determination of proved reserves	¾	(15,735)	(84,840)
Capitalized exploratory well costs charged to expense	¾	(6,980)	(5,388)
Balance at end of period	4,161	2,996	6,964
Less exploratory well costs that have been capitalized for a period of one year or less	(1,165)	(2,996)	¾
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$2,996	$¾	$6,964
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	1	¾	1

As of December 31, 2015, the $3.0 million of capitalized exploratory well costs that have been capitalized for more than one year is comprised of one well in our Marcellus Shale area which is currently in the completion phase. The following table provides an aging of capitalized exploratory well costs that have been suspended for more than one year as of December 31, 2015 (in thousands):

	Total	2015	2014
Capitalized exploratory well costs that have been suspended for more than one year	$2,996	$ ¾	$2,996

(7) Indebtedness

We had the following debt outstanding as of the dates shown below which are net of debt issuance costs (bank debt interest rate at December 31, 2015 is shown parenthetically) (in thousands). The expenses of issuing debt are capitalized and included as a reduction to debt in the accompanying consolidated balance sheets. These costs are amortized over the expected life of the related instruments. When debt is retired before maturity, or modifications significantly change the cash flows, the related unamortized costs are expensed. No interest was capitalized during 2015, 2014, and 2013.

	December 31,	
	2015	2014
Bank debt (1.8%), net of unamortized debt issuance costs of $8,573 and $9,779	$86,427	$713,221
Senior notes:		
4.875% senior notes due 2025, net of unamortized debt issuance costs of $11,899	738,101	¾
Senior subordinated notes:		
6.75% senior subordinated notes due 2020, net of unamortized debt issuance costs of $6,157	¾	493,843
5.75% senior subordinated notes due 2021, net of unamortized debt issuance costs of $5,905 and $6,803	494,095	493,197
5.00% senior subordinated notes due 2022, net of unamortized debt issuance costs of $7,777 and $8,820	592,223	591,180
5.00% senior subordinated notes due 2023, net of unamortized debt issuance costs of $9,543 and $10,617	740,457	739,383
Total debt	$2,651,303	$3,030,824

Bank Debt

In October 2014, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets. The bank credit facility has a maximum facility amount of $4.0 billion. As of December 31, 2015, the facility had a borrowing base of $3.0 billion and bank commitments of $2.0 billion. The bank credit facility provides for a borrowing base subject to redeterminations annually each May and for event-driven unscheduled redeterminations. As part of our annual redetermination completed on March 31, 2015, our borrowing base was reaffirmed at $3.0 billion and our bank commitment was also reaffirmed at $2.0 billion. Our current bank group is comprised of twenty-nine financial institutions, with no one bank holding more than 5.8% of the total facility. The borrowing base may be increased or decreased based on our request and sufficient proved reserves, as determined by the bank group. The commitment amount may be increased to the borrowing base, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility increase. The commitment matures on October 16, 2019. As of December 31, 2015, the outstanding balance under the bank credit facility was $95.0 million with $137.9 million of undrawn letters of credit leaving $1.8 billion of borrowing capacity available under the commitment amount. See additional discussion below under "Debt Covenants and Maturity". During a non-investment grade period, borrowings under the bank facility can either be at the alternate base rate ("ABR," as defined in the bank credit agreement) plus a spread ranging from 0.25% to 1.25% or LIBOR borrowings at the LIBOR Rate (as defined in the bank credit agreement) plus a spread ranging from 1.25% to 2.25%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to ABR loans or to convert all or any of the ABR loans to LIBOR loans. The weighted average interest rate was 1.7% for the year ended December 31, 2015 and 2.0% for each of the years ended December 31, 2014 and 2013. A commitment fee is paid on the undrawn balance based on an annual rate of 0.30% to 0.375%. At December 31, 2015, the commitment fee was 0.30%, the interest rate margin was 1.25% on our LIBOR loans and 0.25% on our base rate loans.

At any time during which we have an investment grade debt rating from Moody's Investors Service, Inc. or Standard & Poor's Ratings Services and we have elected, at our discretion, to effect the investment grade rating period, certain collateral security requirements, including the borrowing base requirement and restrictive covenants will cease to apply, certain other restrictive covenants will become less restrictive and an additional financial covenant (as defined in the bank credit facility) will be temporarily imposed. During the investment grade period, borrowings under the bank credit facility can either be at the ABR plus a spread ranging from 0.125% to 0.75% or LIBOR Rate plus a spread ranging from 1.125% to 1.75% depending on our debt rating. The commitment fee paid on the undrawn balance ranges from 0.15% to 0.30%. We currently do not have an investment grade rating.

Senior Notes

In May 2015, we issued $750.0 million aggregate principal amount of 4.875% senior notes due 2025 (the "4.875% Notes") for net proceeds of $737.4 million after underwriting discounts and commissions of $12.6 million. The notes were issued at par. The 4.875% Notes were offered to qualified institutional buyers and to non-U.S. persons outside the United States in compliance with Rule 144A and Regulation S of the Securities Act of 1933, as amended (the "Securities Act"). Interest due on the 4.875% Notes is payable semi-annually in May and November and is unconditionally guaranteed on a senior unsecured basis by all of our subsidiary guarantors. On or after February 15, 2025, we may redeem the notes, in whole or in part and from time to time, at 100% of the principal amount, plus accrued and unpaid interest. Upon the occurrence of certain changes in control, we must offer to repurchase the 4.875% Notes. The 4.875% Notes are unsecured and are subordinated to all of our existing and future secured debt, rank equally with all of our existing and future senior unsecured debt, and rank senior to all of our existing and future subordinated debt. On the closing of the 4.875% Notes, we used the net proceeds to repay borrowings under our bank credit facility pending our intended redemption of all of our 6.75% senior subordinated notes due 2020, which was completed in August 2015 using borrowings under our bank credit facility.

Senior Subordinated Notes

If we experience a change of control, noteholders may require us to repurchase all or a portion of all of our senior subordinated notes at 101% of the principal amount plus accrued and unpaid interest, if any. All of the senior subordinated notes and the guarantees by our subsidiary guarantors are general, unsecured obligations and are subordinated to our bank debt and will be subordinated to future senior debt that we or our subsidiary guarantors are permitted to incur under the bank credit facility and the indentures governing the subordinated notes.

Early Extinguishment of Debt

In July 2015, we announced a call for the redemption of $500.0 million of our outstanding 6.75% senior subordinated notes due 2020 at a price of 103.375% of par plus accrued and unpaid interest, which were redeemed on August 3, 2015. In third quarter 2015, we recognized a loss on early extinguishment of debt of $22.5 million, including transaction call premium costs and the expensing of the remaining deferred financing costs on the repurchased debt.

In 2014, we announced a call for the redemption of $300.0 million of our outstanding 8.0% senior subordinated notes due 2019 at 104.0% of par plus accrued and unpaid interest which were redeemed on June 26, 2014. In second quarter 2014, we recognized a $24.6 million loss on extinguishment of debt, including transaction call premium costs as well as expensing of the remaining deferred financing costs on the repurchased debt.

In 2013, we announced a call for the redemption of $250.0 million of our outstanding 7.25% senior subordinated notes due 2018 at 103.625% of par which were redeemed on May 2, 2013. In second quarter 2013, we recognized a $12.3 million loss on extinguishment of debt, including transaction call premium costs as well as expensing of the remaining deferred financing costs on the repurchased debt.

Guarantees

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees by our wholly owned subsidiaries, which are directly or indirectly owned by Range, of our senior notes, our senior subordinated notes and our bank credit facility are full and unconditional and joint and several, subject to certain customary release provisions. A subsidiary guarantor may be released from its obligations under the guarantee:

- in the event of a sale or other disposition of all or substantially all of the assets of the subsidiary guarantor or a sale or other disposition of all the capital stock of the subsidiary guarantor, to any corporation or other person (including an unrestricted subsidiary of Range) by way of merger, consolidation, or otherwise; or
- if Range designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the terms of the indenture.

Debt Covenants and Maturity

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make certain investments. In addition, we are required to maintain a ratio of EBITDAX (as defined in the credit agreement) to cash interest expense of equal to or greater than 2.5 and a current ratio (as defined in the credit agreement) of no less than 1.0. In addition, the ratio of the present value of proved reserves (as defined in the credit agreement) to total debt must be equal to or greater than 1.5 until Range has two investment grade ratings. We were in compliance with applicable covenants under the bank credit facility at December 31, 2015.

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical to each other and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates, or change the nature of our business. At December 31, 2015, we were in compliance with these covenants. Our senior subordinated notes also include a limitation on the amount of credit facility debt we can incur. Certain thresholds, as set forth in the indenture debt incurrence test, may limit our ability to incur debt under our bank credit facility in excess of a $1.5 billion floor amount based on the levels of commodity prices for natural gas, NGLs and crude oil used in the annual calculation of discounted future net cash flows relating to proved oil and gas reserves. Based on the year-end 2015 discounted future net cash flows, our bank credit facility usage is limited to $1.5 billion until higher prices or proved reserve additions increase discounted future net cash flows.

The following is the principal maturity schedule for our long-term debt outstanding as of December 31, 2015 (in thousands):

	Year Ended December 31,
2016	$ —
2017	—
2018	—
2019	95,000
2020	—
Thereafter	2,600,000
	$ 2,695,000

(8) Asset Retirement Obligations

Our asset retirement obligations primarily represent the present value of the estimated amounts we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well life. The inputs are calculated based on historical data as well as current estimated costs. A reconciliation of our liability for plugging and abandonment costs as of December 31, 2015 and 2014 are as follows (in thousands):

	2015	2014
Beginning of period	$287,463	$230,077
Liabilities incurred	4,595	8,602
Acquisitions	1,584	11,927
Liability released	¾	(8,309)
Liabilities settled	(18,828)	(4,442)
Disposition of wells	(45,845)	(13,951)
Accretion expense	19,163	15,226
Change in estimate	16,005	48,333
End of period	264,137	287,463
Less current portion	(15,071)	(15,067)
Long-term asset retirement obligations	$249,066	$272,396

Accretion expense is recognized as an increase to depreciation, depletion and amortization expense in the accompanying consolidated statements of operations.

(9) Capital Stock

We have authorized capital stock of 485.0 million shares, which includes 475.0 million shares of common stock and 10.0 million shares of preferred stock. The following is a schedule of changes in the number of common shares outstanding since the beginning of 2013:

	Year Ended December 31,		
	2015	2014	2013
Beginning balance	168,628,177	163,342,894	162,514,098
Equity offering	–	4,560,000	–
Stock options/SARs exercised	77,002	195,242	278,916
Restricted stock grants	335,103	270,062	401,122
Restricted stock units vested	252,507	244,413	119,480
Treasury shares	23,671	15,566	29,278
Ending balance	169,316,460	168,628,177	163,342,894

Common Stock Dividends

The board of directors declared quarterly dividends of $0.04 per common share for each of the four quarters of 2015, 2014 and 2013. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the board of directors and will depend on our financial condition, earnings and cash flow from operations, level of capital expenditures, our future business prospects and other matters our board of directors deem relevant. Our bank credit facility and our senior subordinated notes allow for the payment of common dividends, with certain limitations. Dividends are limited to our legally available funds.

(10) Derivative Activities

We use commodity-based derivative contracts to manage exposure 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 swap or collar contracts to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a net unrealized pretax gain of $283.3 million at December 31, 2015. These contracts expire monthly through December 2017. The following table sets forth the derivative volumes by year as of December 31, 2015:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2016	Swaps	745,874 Mmbtu/day	$3.24
2017	Swaps	20,000 Mmbtu/day	$3.49
Crude Oil			
2016	Swaps	4,247 bbls/day	$65.27
2017	Swaps	500 bbls/day	$55.00
NGLs (C3 - Propane)			
2016	Swaps	5,500 bbls/day	$0.60/gallon
NGLs (NC4 – Normal Butane)			
2016	Swaps	2,500 bbls/day	$0.72/gallon
NGLs (C5 - Natural Gasoline)			
2016	Swaps	2,749 bbls/day	$1.20/gallon

Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. Through February 28, 2013, changes in the fair value of our derivatives that qualified for hedge accounting were recorded as a component of AOCI in the stockholders' equity section of the our consolidated balance sheets and were later transferred to natural gas, NGLs and oil sales when the underlying physical transaction occurred and the hedging contract was settled. Due to the discontinuance of hedge accounting in early 2013, all remaining AOCI hedging gains were transferred to earnings in 2014. See additional discussion below regarding the discontinuance of hedge accounting. If the derivative does not qualify as a hedge or is not designated as a hedge, changes in fair value of these non-hedge derivatives are recognized in earnings in derivative fair value income or loss.

Basis Swap Contracts

At December 31, 2015, we had natural gas basis swap contracts which lock in the differential between NYMEX and certain of our physical pricing points in Appalachia. These contracts settle monthly through March 2017 and include a total volume of 53,365,000 Mmbtu. The fair value of these contracts was a gain of $5.5 million on December 31, 2015.

At December 31, 2015, we also had propane basis swap contracts which lock in the differential between Mont Belvieu and international propane indexes. The contracts settle monthly through December 2016 and include a total volume of 4,679 bbls/day. The fair value of these contracts was a loss of $1.1 million on December 31, 2015.

Discontinuance of Hedge Accounting

Effective March 1, 2013, we elected to de-designate all commodity contracts that were previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. AOCI included gains of $103.6 million ($63.2 million after tax) as of February 28, 2013. As a result of discontinuing hedge accounting, the mark-to-market values included in AOCI as of the de-designation date were frozen and were reclassified into earnings in natural gas, NGLs and oil sales in future periods as the underlying hedged transactions occurred. As of December 31, 2014, all frozen values have been reclassified to earnings.

For those derivative instruments that qualified for hedge accounting, settled transaction gains and losses were determined monthly and were included as increases or decreases to natural gas, NGLs and oil sales in the period the hedged production was sold. Through February 28, 2013, we had elected to designate our commodity instruments that qualified for hedge accounting as cash flow hedges. Natural gas, NGLs and oil sales include $10.2 million of gains in 2014 compared to gains of $116.5 million in 2013 related to settled hedging transactions. Any ineffectiveness associated with these hedge derivatives are reflected in derivative fair value income or loss in the accompanying consolidated statements of operations. The ineffective portion is calculated as the difference between the changes in fair value of the derivative and the estimated change in future cash flows from the item hedged.

All of our derivative instruments continue to be recorded at fair value with all changes in fair value recognized immediately in earnings rather than in AOCI. These mark-to-market adjustments will produce a degree of earnings volatility that can be significant from period to period, but such adjustments will have no cash flow impact relative to changes in market prices. The impact to cash flow occurs upon settlement of the underlying contract.

Derivative assets and liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of December 31, 2015 and 2014 is summarized below (in thousands). As of December 31, 2015, we are conducting derivative activities with seventeen counterparties, of which all but four are secured lenders in our bank credit facility. We believe all of these counterparties are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty and we have master netting arrangements.

		December 31, 2015		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$219,357	$ (10,245)	$ 209,112
	–natural gas basis swaps	8,251	(2,765)	5,486
Crude oil	–swaps	38,699	¾	38,699
NGLs	–C3 swaps	15,884	¾	15,884
	–C3 basis	2,497	(2,497)	¾
	–C4 swaps	6,968	¾	6,968
	–C5 swaps	12,694	(81)	12,613
		$304,350	$ (15,588)	$ 288,762

		December 31, 2015		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–swaps	$(10,245)	$ 10,245	$ ¾
	–natural gas basis swaps	(2,786)	2,765	(21)
NGLs	–C3 basis	(3,633)	2,497	(1,136)
	–C5 swaps	(81)	81	¾
		$(16,745)	$ 15,588	$ (1,157)

		December 31, 2014		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$198,740	$ ¾	$ 198,740
	–collars	57,460	¾	57,460
	–basis swaps	2,442	(755)	1,687
Crude oil	–swaps	128,578	¾	128,578
NGLs	–C3 swaps	14,727	¾	14,727
	–C5 swaps	2,171	¾	2,171
		$404,118	$ (755)	$ 403,363

		December 31, 2014		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–basis swaps	$ (755)	$ 755	$ –
		$ (755)	$ 755	$ –

The effects of our non-hedge derivatives (or those derivatives that do not qualify or are not designated for hedge accounting) on our consolidated statements of operations for the last three years are summarized below (in thousands). Derivative fair value for the year ended December 31, 2014 includes no ineffective gains or losses compared to ineffective loss of $2.9 million in the year ended December 31, 2013.

	Year Ended December 31, Derivative Fair Value Income (Loss)		
	2015	2014	2013
Swaps	$398,020	$367,484	$(50,526)
Re-purchased swaps	851	¾	1,323
Collars	16,539	42,836	(16,062)
Basis swaps	954	(26,800)	3,440
Total	$416,364	$383,520	$(61,825)

(11) Fair Value Measurements

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 amount 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 reporting 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 reporting date.
- Level 3 – Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair 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.

Fair Values-Recurring

We use a market approach for our recurring fair value measurements and endeavor to use the best information available. Accordingly, valuation techniques that maximize the use of observable impacts are favored. The following tables present the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis (in thousands):

	Fair Value Measurements at December 31, 2015 Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2015
Trading securities held in the deferred compensation plans	$62,376	$ ¾	$ ¾	$ 62,376
Derivatives–swaps	¾	283,276	¾	283,276
–basis swaps	¾	4,329	¾	4,329

	Fair Value Measurements at December 31, 2014 Using:			
	Quoted Prices in Active Markets for	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2014

	Identical Assets (Level 1)			
Trading securities held in the deferred compensation plans	$68,454	$ —	$ —	$ 68,454
Derivatives–swaps	—	344,216	—	344,216
–collars	—	57,460	—	57,460
–basis swaps	—	1,687	—	1,687

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using December 31, 2015 market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes.

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in the accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends, and mark-to-market gains/losses are included in deferred compensation plan expense in the accompanying consolidated statements of operations. For the year ended December 31, 2015, interest and dividends were $908,000 and mark-to-market was a loss of $5.9 million. For the year ended December 31, 2014, interest and dividends were $911,000 and mark-to-market was a loss of $2.4 million. For the year ended December 31, 2013, interest and dividends were $1.2 million and mark-to-market was a gain of $3.9 million.

Fair Values-Non recurring

Due to declines in commodity prices and estimated reserves over the last three years, there were indications that the carrying values of certain of our natural gas and oil properties may be impaired and undiscounted future cash flows attributed to these assets indicated their carrying amounts were not expected to be recovered. Their fair value was measured using an income approach based upon internal estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 inputs. In some cases, we also considered the potential sale of certain of these properties. We recorded non-cash charges during the year ended 2015 related to natural gas and oil properties in Northern Oklahoma of $306.6 million, $195.6 million related to our shallow legacy oil and natural gas assets in Northwest Pennsylvania, $86.9 million related to our assets in the Texas Panhandle and $1.1 million related to onshore Gulf Coast properties. We recorded non-cash charges during the year ended 2014 of $5.5 million related to natural gas and oil properties in Mississippi, $18.5 million related to properties in West Texas and $4.0 million to fully impair our remaining oil and natural gas properties in North Texas. We recorded non-cash charges during the year ended 2013 of $7.0 million related to Gulf Coast onshore oil and gas properties. Also in 2013, we evaluated certain surface property we own which included a consideration for the potential sale of the assets and we recognized impairment charges of $741,000 in 2013. The following table presents the value of these assets measured at fair value on a nonrecurring basis at the time impairment was recorded (in thousands):

	Year Ended December 31,					
	2015		2014		2013	
	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Natural gas and oil properties	$152,230	$590,174	$15,605	$ 28,024	$500	$ 7,012
Surface property	¾	¾	¾	¾	5,550	741

Fair Values - Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of December 31, 2015 and 2014 (in thousands):

	December 31, 2015		December 31, 2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars and basis swaps	$288,762	$288,762	$403,363	$403,363
Marketable securities[(a)]	62,376	62,376	68,454	68,454
Liabilities:				
Commodity swaps, collars and basis swaps	(1,157)	(1,157)	¾	¾
Bank credit facility[(b)]	(95,000)	(95,000)	(723,000)	(723,000)
Deferred compensation plan[(c)]	(122,918)	(122,918)	(203,433)	(203,433)
4.875% senior notes due 2025[(b)]	(750,000)	(572,813)	¾	¾
6.75% senior subordinated notes due 2020[(b)]	¾	¾	(500,000)	(523,125)
5.75% senior subordinated notes due 2021[(b)]	(500,000)	(396,250)	(500,000)	(520,000)
5.00% senior subordinated notes due 2022[(b)]	(600,000)	(447,000)	(600,000)	(601,500)
5.00% senior subordinated notes due 2023[(b)]	(750,000)	(551,250)	(750,000)	(754,688)

(a) Marketable securities are held in our deferred compensation plans that are actively traded on major exchanges.

(b) The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior notes and our senior subordinated notes is based on end of period market quotes, which are Level 2 inputs.

(c) The fair value of our deferred compensation plan is updated based on closing prices on the balance sheet date.

Our current assets and liabilities contain financial instruments, the most significant of which are trade accounts receivables and payables. We believe the carrying values of our current assets and liabilities approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments and (2) our historical incurrence of and expected future insignificance of bad debt expense.

(12) Stock-based Compensation Plans
Description of the Plans

The 2005 Equity Based Compensation Plan (the "2005 Plan") authorizes the compensation committee of the board of directors to grant, among other things, stock options, SARs, PSUs and restricted stock awards to employees. The 2005 Plan also allows us to provide equity compensation to our non-employee directors. The 2005 Plan was approved by stockholders in May 2005 and replaced our 1999 Stock Option Plan. The number of shares that may be issued under the 2005 Plan is equal to (i) 5.6 million shares plus (ii) the number of shares subject to 1999 Stock Option Plan awards outstanding at May 18, 2005 that subsequently lapse or terminate without the underlying shares being issued plus (iii) subsequent shares approved by the stockholders.

After the approval of the 2005 Plan, no new grants have been made from the 1999 Stock Option Plan. In addition, our 2004 Non-Employee Director Stock Option Plan (the "Director Plan") expired at the end of 2014. Any awards previously granted under the 1999 Stock Option Plan or the Director Plan continue to be exercisable in accordance with their original terms and conditions.

Stock-Based Awards

Prior to 2005, we granted stock options under our various stock option plans. Stock options represent the right to purchase shares of stock in the future at the fair value of the stock on the date of grant. Beginning in 2005, we began granting SARs to reduce the dilutive impact of our equity plans. Similar to stock options, SARs represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the value of the stock on the date of grant. All SARs granted will be settled in shares of stock, vest over a three-year period and have a maximum term of five years from the date they are granted. Beginning in first quarter 2011, we began granting restricted stock units under our equity-based stock compensation plan. These restricted stock units, which we refer to as restricted stock Equity Awards, vest over a three-year period. In first quarter 2014, we began granting PSU awards. The number of shares to be issued is determined by our total shareholder return compared to the total shareholder return of a predetermined group of peer companies over the performance period. The PSU awards vest at the end of the three-year performance period. The grant date fair value of the PSU awards is determined using a Monte Carlo simulation and is recognized as stock-based compensation expense over the three-year performance period. All awards granted have been issued at prevailing market prices at the time of grant and the vesting of these shares is based upon an employee's continued employment with us.

The compensation committee also grants restricted stock to certain employees and non-employee directors of the board of directors as part of their compensation. Compensation expense is recognized over the balance of the vesting period, which is typically three years for employee grants and immediate vesting for non-employee directors. All restricted stock awards are issued at prevailing market prices at the time of the grant and the vesting is based upon an employee's continued employment with us. Prior to vesting, all restricted stock awards have the right to vote such stock (by the trustee) and receive dividends thereon. Upon grant of these restricted shares, which we refer to as restricted stock Liability Awards, the majority of these shares are placed in our deferred compensation plan and, upon vesting, withdrawals are allowed in either cash or in stock. These Liability Awards are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market amount is reported in deferred compensation plan expense in the accompanying consolidated statements of operations. Historically, we have used authorized but unissued shares of stock when restricted stock is granted. However, we also utilize treasury shares when available.

Total Stock-Based Compensation Expense

Stock-based compensation expense represents amortization of restricted stock, PSUs and SARs grants. The following table details the amount of stock-based compensation that is allocated to functional expense categories for each of the years in the three-year period ended December 31, 2015 (in thousands):

	2015	2014	2013
Direct operating expense	$ 2,780	$ 4,208	$ 2,755
Brokered natural gas and marketing expense	2,132	3,523	1,852
Exploration expense	2,985	4,569	4,025
General and administrative expense	49,687	55,382	55,737
Termination costs	217	2,999	¾
Total	$ 57,801	$ 70,681	$ 64,369

Unlike the other forms of stock-based compensation expense mentioned above, the mark-to-market of the liability related to the vested restricted stock held in our deferred compensation plans is directly tied to the change in our stock price and not directly related to the functional expenses and therefore, is not allocated to the functional categories and is reported as deferred compensation plan expense in the accompanying consolidated statement of operations.
Stock-based compensation expense in the year ended December 31, 2014 includes $6.7 million of awards granted to our former executive chairman for his 2013 service while he was a Range officer,

which were fully vested upon grant. In 2015, the tax deduction for stock-based compensation was less than the book stock-based compensation expense for equity compensation grants vested or exercised during the year. The tax effect of the deduction was recorded as a reduction to additional paid-in capital. For the years ended December 31, 2014 and 2013, tax benefits realized for deductions that were in excess of the stock-based compensation expense were not recognized due to our net operating loss position.

Performance Share Unit Awards

The following is a summary of our non-vested PSU award activities:

	Number of Units [a]	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2013	—	$ —
Granted	227,929	86.14
Vested [b]	(92,077)	86.23
Forfeited	(1,511)	82.60
Outstanding at December 31, 2014	134,341	86.11
Granted	276,204	56.78
Vested [c]	(143,094)	68.73
Forfeited	(5,327)	82.60
Outstanding at December 31, 2015	262,124	$ 64.77

[a] These amounts reflect the number of performance units granted. The actual payout of shares may be between zero percent and 150% of the performance units granted depending on the total shareholder return ranking compared to our peer companies at the vesting date.

[b] Primarily represents PSU awards granted to our prior executive chairman for the 2013 calendar year while he was a Range officer.

[c] Includes PSU awards of 19,684 that were modified and fully vested effective with the closing of our Oklahoma City Office and the sale of our Virginia and West Virginia assets.

A Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. Expected volatilities utilized in the model were estimated using a combination of a historical period consistent with the remaining performance period of three years and option implied volatilities. The risk-free interest rate was based on the United States Treasury rate for a term commensurate with the life of the grant. The following assumptions were used to estimate the fair value of PSUs granted during the year ended December 31, 2015 and 2014:

	Year Ended December 31, 2015	2014
Risk-free interest rate	1.02 %	0.77 %
Expected annual volatility	33 %	33 %
Grant date fair value per unit	$56.78	$86.14

We recorded PSU compensation expense of $8.7 million in the year ended December 31, 2015 compared to $7.9 million in the year ended December 31, 2014 and none in the same period of 2013. As of December 31, 2015, there was $15.7 million of unrecognized compensation related to PSU awards to be recognized over a weighted average period of 1.9 years.

Restricted Stock Awards

Equity Awards

In 2015, we granted 588,000 restricted stock Equity Awards to employees which generally vest over a three-year period compared to 356,000 in 2014 and 402,000 in 2013. We recorded compensation expense for these awards of $23.8 million in the year ended December 31, 2015 compared to $28.1 million in 2014 and $19.7 million in 2013. As of December 31, 2015, there was $23.8 million of unrecognized compensation related to Equity Awards expected to be recognized over a weighted average period of 1.7 years. Restricted stock Equity Awards are not issued to employees until such time as they are vested and the employees do not have the option to receive cash.

Liability Awards

In 2015, we granted 343,000 shares of restricted stock Liability Awards as compensation to directors and employees at an average price of $55.92. This grant included 48,000 issued to non-employee directors which vest immediately and 295,000 to employees with vesting generally over a three-year period. In 2014, we granted 272,000 shares of restricted stock Liability Awards as compensation to directors and employees at an average price of $87.34. This grant included 64,000 issued to non-employee directors, which vest immediately and 208,000 to employees with vesting generally over a three-year period. In 2013, we granted 425,000 shares of restricted stock Liability Awards as compensation to directors and employees at an average price of $75.53. This grant included 18,000 issued to non-employee directors, which vest immediately, and 407,000 to employees with vesting generally over a three-year period. We recorded compensation expense for these Liability Awards of $20.8 million in the year ended December 31, 2015 compared to $26.3 million in 2014 and $27.4 million in 2013. As of December 31, 2015, there was $18.1 million of unrecognized compensation related to restricted stock Liability Awards expected to be recognized over a weighted average period of 1.8 years. The majority of all of these awards are held in our deferred compensation plan, are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market is reported as deferred compensation expense in our consolidated statements of operations (see additional discussion below). The proceeds received from the sale of stock held in our deferred compensation plan were $8.3 million in 2015 compared to $16.0 million in 2014 and $20.7 million in 2013. A summary of the status of our non-vested restricted stock outstanding at December 31, 2015 is summarized below:

	Equity Awards		Liability Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2012	349,156	$ 59.08	423,478	$ 58.91
Granted	402,053	71.26	424,809	75.53
Vested	(315,535)	62.43	(437,570)	64.36
Forfeited	(50,611)	65.29	(21,704)	57.31
Outstanding at December 31, 2013	385,063	68.24	389,013	71.02
Granted	356,194	84.87	272,052	87.34
Vested	(354,237)	72.85	(356,413)	75.52
Forfeited	(26,605)	75.66	(148)	77.35
Outstanding at December 31, 2014	360,415	79.60	304,504	80.33
Granted	587,711	52.29	343,397	55.92
Vested	(480,253)	65.21	(330,870)	68.71
Forfeited	(31,109)	64.73	(8,294)	74.22
Outstanding at December 31, 2015	436,764	$ 59.74	308,737	$ 65.80

Stock Appreciation Right Awards

During 2014 and 2013, we granted SARs to officers, non-officers employees and directors. Information with respect to our SARs activities is summarized below. During 2014, we granted SARs to our former executive chairman in conjunction with his retirement from Range as an employee.

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2012	3,433,362	$ 52.52

Granted	470,617		75.82
Exercised	(1,269,323)		53.24
Expired/forfeited	(52,582)		53.56
Outstanding at December 31, 2013	2,582,074		56.36
Granted	1,104		81.74
Exercised	(616,563)		45.45
Expired/forfeited	(66)		46.44
Outstanding at December 31, 2014	1,966,549		59.80
Exercised	(427,598)		45.67
Expired/forfeited	(27,974)		63.10
Outstanding at December 31, 2015	1,510,977	$	63.73

The following table shows information with respect to SARs outstanding and exercisable at December 31, 2015:

	Outstanding			Exercisable	
Range of Exercise Prices	Shares	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
$ 40.00–$ 49.99	112,769	0.13	$ 49.18	112,769	$ 49.18
50.00–59.99	355,052	0.38	52.35	355,052	52.35
60.00–69.99	602,926	1.34	64.19	602,926	64.19
70.00–79.99	438,330	2.28	75.99	301,641	76.08
80.00–81.15	1,900	2.69	81.15	1,900	81.15
Total	1,510,977	1.30	$ 63.73	1,374,288	$ 62.53

The weighted average grant date fair value of these SARs, based on our Black-Scholes-Merton assumptions, is shown below:

	2014	2013
Weighted average exercise price per share	$81.74	$75.82
Expected annual dividend yield	0.20 %	0.21 %
Expected life in years	4.3	3.7
Expected volatility	33 %	35 %
Risk-free interest rate	1.4 %	0.6 %
Weighted average grant date fair value per share	$23.17	$20.20

The expected dividend yield is based on the current annual dividend at the time of grant. The expected life was based on the historical exercise activity. The expected volatility factors are based on a combination of both the historical volatilities of the stock and implied volatility of traded options on our common stock. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options.

The total intrinsic value (the difference in value between exercise and market price at the time of grant) of SARs exercised during the year ended December 31, 2015 was $5.4 million compared to $27.1 million in 2014 and $30.3 million in 2013. As of December 31, 2015, there was no aggregate intrinsic value for any of the awards exercisable or awards outstanding. The weighted average remaining contractual life of awards exercisable was 1.2 years. As of December 31, 2015, the number of fully vested awards and the awards expected to vest was 1.5 million shares. The weighted average exercise price and weighted average remaining contractual life of these awards were $63.72 and 1.3 years. As of December 31, 2015, unrecognized compensation cost related to the awards was $701,000, which is expected to be recognized over a weighted average period of 0.4 years.

401(k) Plan

We maintain a 401(k) benefit plan that allows employees to contribute up to 75% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. We match up to 6% of salary in cash and vesting of those contributions is immediate. In 2015, we contributed $6.1 million to the 401(k) Plan compared to $5.8 million in 2014. Employees have a variety of investment options in the 401(k) benefit plan.

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 Range common stock or make other investments at the individual's discretion. Range provides a partial matching contribution which vests over three years. The assets of the plans are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability for the vested portion of the stock held in the Rabbi Trust is reflected in the deferred compensation liability in the accompanying consolidated balance sheets and is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at their market value in other assets in the accompanying consolidated balance sheets. The deferred compensation liability reflects the vested market value of the marketable securities and Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities and changes in the fair value of the deferred compensation plan liability are charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market gain of $77.6

million in 2015 compared to a gain of $74.6 million in 2014 and a loss of $55.3 million in 2013. The Rabbi Trust held 2.8 million shares (2.5 million of vested shares) of Range stock at both December 31, 2015 and 2014.

(13) Supplemental Cash Flow Information

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Net cash provided from operating activities included:			
Income taxes paid to (refunded from) taxing authorities	$ 100	$ (156)	$ (347)
Interest paid	168,826	165,530	159,137
Non-cash investing and financing activities included:			
Asset retirement costs capitalized, net	$ 22,184	$ 56,822	$ 76,373
(Decrease) increase in accrued capital expenditures	(225,455)	150,604	27,079

(14) Commitments and Contingencies

Litigation

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 on a quarterly basis and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then current status of litigation.

Lease Commitments

We lease certain office space, office equipment, production facilities, compressors and transportation equipment under cancelable and non-cancelable leases. Rent expense under operating leases (including renewable monthly leases) totaled $15.9 million in 2015 compared to $13.3 million in 2014 and $13.1 million in 2013. Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. Future minimum rental commitments under non-cancelable leases having remaining lease terms in excess of one year are as follows (in thousands):

	Operating Lease Obligations
2016	$ 11,819
2017	10,014
2018	8,902
2019	7,264
2020	7,238
Thereafter	29,258
	$ 74,495

Transportation and Gathering Contracts

We have entered into firm transportation and gathering contracts with various pipeline carriers for the future transportation and gathering of natural gas, NGLs and oil production primarily from our properties in Pennsylvania. Under these contracts, we are obligated to transport or gather minimum daily natural gas volumes, or pay for any deficiencies at a specified reservation fee rate. In most cases, our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. As of December 31, 2015, future minimum transportation and gathering fees under our commitments are as follows (in thousands):

	Transportation and Gathering Contracts [a]
2016	$ 407,046
2017	401,517
2018	366,914
2019	366,562
2020	359,595
Thereafter	1,748,559
	$ 3,650,193

[a] The amounts in this table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest which can vary based on volumes produced.

In addition to the amounts included in the above table, we have entered into additional agreements which are contingent on certain pipeline and gathering line modifications and/or construction. These agreements range between six and twenty year terms and are expected to begin in 2016 and 2017. Based on these contracts, we will have additional transportation obligations for natural gas volumes of 2.0 bcf per day until 2026, declining to 1.3 bcf per day through 2032 and 400,000 mcf per day until 2037. We also have gathering obligations which begin in 2017 of up to 400,000 mcf per day through 2032. Beginning in 2016, we also have transportation obligations for ethane volumes of 20,000 bbls per day and propane volumes of 20,000 bbls per day through the end of 2031.

Delivery Commitments

We have various volume delivery commitments that are primarily related to our Marcellus Shale and Oklahoma and Texas 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, 2015, our delivery commitments through 2028 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2016	405,126	40,000
2017	241,301	40,000
2018	—	40,000
2019	—	20,000
2020	—	20,000
2021	—	20,000

2022¾2028	—	15,000

In addition to the amounts included in the above table, we have contracted with several pipeline companies through 2033 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 20,000 bbls per day starting in 2016, increasing to 30,000 bbls per day in 2018 and 45,000 bbls per day in 2020 through the end of the term. 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 50,000 mcf per day starting in late 2017, increasing to 200,000 mcf per day in early 2019 and 300,000 mcf per day in late 2019.

Other

We also have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three to 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, 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.

(15) Equity Method Investments

We accounted for our investments in entities over which we had significant influence, but not control, using the equity method of accounting. Under the equity method of accounting, we recorded our proportionate share of net earnings, declared dividends and partnership distributions based on the most recently available financial statements of the investee. We also evaluated our equity method investments for potential impairment whenever events or changes in circumstances indicate that there is an other than temporary decline in value of the investment. Such events include sustained operating losses by the investee or long-term negative changes in the investee’s industry. As of June 2014, we no longer have equity method investments.

Investment in Whipstock Natural Gas Services, LLC

In 2006, we acquired a 50% interest in Whipstock Natural Gas Services, LLC (“Whipstock”), an unconsolidated investee in the business of providing oil and gas drilling equipment, well servicing rigs and equipment, and other well services in Appalachia. On the acquisition date, we contributed cash of $11.7 million representing the fair value of 50% of the membership interest in Whipstock. In September 2013, we sold our equity method investment in Whipstock for proceeds of $7.0 million and recognized a gain of $4.4 million.

Investment in Nora Gathering, LLC

In May 2007, we completed the initial closing of a joint development arrangement with EQT Corporation (“EQT”). Pursuant to the terms of the arrangement, Range and EQT (“the parties”) agreed to, among other things, form a new pipeline and natural gas gathering operations entity, Nora Gathering, LLC (“NGLLC”). NGLLC was an unconsolidated investee created by the parties for the purpose of conducting pipeline, natural gas gathering, and transportation operations associated with the parties’ collective interests in properties in the Nora Field. In connection with the formation, we contributed cash of $94.7 million for a 50% membership interest in NGLLC.

NGLLC followed a calendar year basis of financial reporting consistent with us and our equity in NGLLC earnings from the acquisition date is included in brokered natural gas, marketing and other revenue in the accompanying consolidated statements of operations for 2014 and 2013. In 2014, we received partnership distributions of $7.0 million compared to $9.0 million in 2013. In determining our proportionate share of the net earnings of NGLLC, certain adjustments were required to be made to NGLLC’s reported results to eliminate the profits recognized by NGLLC included in the gathering and transportation fees charged to us on production in the Nora Field. For the six months ended June 30, 2014, our equity in losses of NGLLC of $277,000 reflects a reduction of $3.1 million to eliminate the profit on gathering and transportation fees charged to us. For the year ended December 31, 2013, our equity in losses of NGLLC of $146,000 reflects a reduction of $7.7 million to eliminate the profit on the gathering and transportation fees charged to us.

On June 16, 2014, as part of our Conger Exchange, we acquired the remaining 50% interest in NGLLC held by EQT. See Note 3 for additional information. As of June 2014, we consolidated these operations into our consolidated financial statements.

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(16) Office Closing and Exit Costs

In first quarter 2015, we announced the closing of our Oklahoma City administrative and operational office in order to lower our general and administrative expenses, due in part to the impact of lower commodity prices on our operations. In fourth quarter 2014, we initially accrued an estimated $8.4 million of termination costs relating to the closure of this office as it was probable of occurring. In early 2015, those plans and personnel involved were finalized which resulted in additional accruals in 2015 for severance and other personnel costs of $275,000, additional accelerated vesting of stock-based compensation of $948,000 and $3.1 million of building lease costs. In addition, the year ended December 31, 2015 includes additional accruals for severance of $11.4 million and a gain of $731,000 of accelerated vesting of stock-based compensation related to the sale of our Virginia and West Virginia properties which closed on December 30, 2015 and additional reductions in our work force due to the lower commodity price environment. The following table details the accrued liability as of December 31, 2015 and December 31, 2014 (in thousands):

	2015	2014
Beginning balance	$5,372	$—
Accrued severance costs	11,706	5,372
Accrued building rent	3,147	—
Payments	(8,595)	—
Ending balance	$11,630	$5,372

The following summarizes our termination costs for the year ended December 31, 2015 and December 31, 2014 (in thousands):

	2015	2014
Severance costs	$11,706	$5,372
Building lease	3,147	—
Stock-based compensation	217	2,999
Total termination costs	$15,070	$8,371

(17) Selected Quarterly Financial Data (Unaudited)
The following tables set forth unaudited financial information on a quarterly basis for each of the last two years. Fourth quarter 2015 includes a loss of $407.7 million from the sale of our Virginia and West Virginia oil and gas properties and impairment expense of $87.9 million related to oil and gas properties in the Texas Panhandle and South Texas. Third quarter 2015 includes impairment expense of $502.2 million related to our Northern Oklahoma and legacy shallow Northwest Pennsylvania assets. Second quarter 2014 includes a gain of $280.1 million from the Conger Exchange (in thousands, except per share data):

	2015				
	March	June	September	December	Total
Revenues and other income:					
Natural gas, NGLs and oil sales	$325,483	$258,053	$252,065	$254,043	$1,089,644
Derivative fair value income (loss)	122,839	(34,791)	202,004	126,312	416,364
Brokered natural gas, marketing and other	14,485	21,339	25,864	30,372	92,060
Total revenue and other income	462,807	244,601	479,933	410,727	1,598,068
Costs and expenses:					
Direct operating	37,137	34,780	35,058	29,388	136,363
Transportation, gathering and compression	89,426	95,198	99,634	112,481	396,739
Production and ad valorem taxes	9,928	9,242	7,336	7,354	33,860
Brokered natural gas and marketing	21,562	27,031	32,331	34,942	115,866
Exploration	7,886	5,025	4,235	4,260	21,406
Abandonment and impairment of unproved properties	11,491	12,330	12,366	11,432	47,619
General and administrative	48,329	55,964	46,178	43,544	194,015
Termination costs	5,950	417	(77)	8,780	15,070
Deferred compensation plan	(5,624)	(7,282)	(43,705)	(21,016)	(77,627)
Interest	39,207	43,479	42,904	40,849	166,439
Loss on early extinguishment of debt	—	—	22,495	—	22,495
Depletion, depreciation and amortization	147,290	151,895	153,993	127,977	581,155
Impairment of proved properties and other	—	—	502,233	87,941	590,174
Loss (gain) on sale of assets	175	(2,909)	681	408,909	406,856
Total costs and expenses	412,757	425,170	915,662	896,841	2,650,430
Income (loss) before income taxes	50,050	(180,569)	(435,729)	(486,114)	(1,052,362)
Income tax expense (benefit):					
Current	—	—	—	29	29
Deferred	22,366	(61,975)	(134,781)	(164,316)	(338,706)
	22,366	(61,975)	(134,781)	(164,287)	(338,677)
Net income (loss)	$27,684	$(118,594)	$(300,948)	$(321,827)	$(713,685)
Net income (loss) per common share:					
Basic	$0.16	$(0.71)	$(1.81)	$(1.93)	$(4.29)
Diluted	$0.16	$(0.71)	$(1.81)	$(1.93)	$(4.29)

	2014 March	June	September	December	Total
Revenues and other income:					
Natural gas, NGLs and oil sales	$572,017	$477,517	$446,067	$416,388	$1,911,989
Derivative fair value (loss) income	(146,850)	(24,109)	142,057	412,422	383,520
Brokered natural gas, marketing and other	32,528	30,052	28,324	39,644	130,548
Total revenue and other income	457,695	483,460	616,448	868,454	2,426,057
Costs and expenses:					
Direct operating	39,795	34,935	37,792	37,961	150,483
Transportation, gathering and compression	74,161	76,809	84,777	89,542	325,289
Production and ad valorem taxes	11,678	10,844	10,110	11,923	44,555
Brokered natural gas and marketing	34,129	34,775	28,706	32,370	129,980
Exploration	14,846	13,621	11,443	23,638	63,548
Abandonment and impairment of unproved properties	9,995	9,332	13,444	14,308	47,079
General and administrative	49,212	56,888	54,963	52,363	213,426
Termination costs	—	—	—	8,371	8,371
Deferred compensation plan	(2,035)	10,519	(46,198)	(36,836)	(74,550)
Interest	45,401	45,488	39,188	38,900	168,977
Loss on early extinguishment of debt	—	24,596	—	—	24,596
Depletion, depreciation and amortization	128,682	133,361	142,450	146,539	551,032
Impairment of proved properties and other	—	24,991	—	3,033	28,024
Loss (gain) on sale of assets	353	(282,064)	(167)	(3,760)	(285,638)
Total costs and expenses	406,217	194,095	376,508	418,352	1,395,172
Income before income taxes	51,478	289,365	239,940	450,102	1,030,885
Income tax expense (benefit):					
Current	6	(1)	—	(4)	1
Deferred	18,951	117,977	93,522	166,052	396,502
	18,957	117,976	93,522	166,048	396,503
Net income	$32,521	$171,389	$146,418	$284,054	$634,382
Net income per common share:					
Basic	$0.20	$1.04	$0.87	$1.68	$3.81
Diluted	$0.20	$1.04	$0.86	$1.68	$3.79

(18) Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities (Unaudited)

Our natural gas and oil producing activities are conducted onshore within the continental United States and all of our proved reserves are located within the United States.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization [(a)]

	December 31, 2015	2014	2013
	(in thousands)		
Natural gas and oil properties:			
Properties subject to depletion	$8,047,181	$9,624,725	$8,225,859
Unproved properties	949,155	943,246	807,022
Total	8,996,336	10,567,971	9,032,881
Accumulated depreciation, depletion and amortization	(2,635,031)	(2,590,398)	(2,274,444)
Net capitalized costs	$6,361,305	$7,977,573	$6,758,437

[a] Includes capitalized asset retirement costs and the associated accumulated amortization.

Costs Incurred for Property Acquisition, Exploration and Development [a]

	December 31,		
	2015	2014	2013
	(in thousands)		
Acquisitions [b]	$¾	$404,252	$¾
Acreage purchases	73,025	226,475	137,538
Development	708,268	1,119,896	938,668
Exploration:			
Drilling	87,505	180,925	189,742
Expense	18,421	58,979	60,384
Stock-based compensation expense	2,985	4,569	4,025
Gas gathering facilities:			
Development	13,337	13,137	47,086
Subtotal	903,541	2,008,233	1,377,443
Asset retirement obligations	22,184	56,822	76,373
Total costs incurred	$925,725	$2,065,055	$1,453,816

(a) Includes cost incurred whether capitalized or expensed.

(b) See also Note 3 for additional information related to the 2014 Conger Exchange which includes $134.8 million of gas gathering assets received in the exchange and $11.9 million of asset retirement obligations added in the exchange.

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

Reserves of natural gas, NGLs, crude oil and condensate are estimated by our petroleum engineering staff and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes, production taxes and other economic factors.

Reserve Audit

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. At year-end 2015, the following independent petroleum consultant conducted an audit of our reserves: Wright and Company, Inc. (Appalachia). These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. At December 31, 2015, our consultant collectively audited approximately 94% of our proved reserves. A copy of the summary reserve reports prepared by our independent petroleum consultant is included as exhibits to this Annual Report on Form 10-K. The technical person at our independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality 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 reserves 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 reserves estimation process, our senior management reviews and approves any 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. The 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 lease-by-lease, field-by-field or area-by-area basis, some of our estimates may be greater and some may be less than the estimates of our reserve auditor. When such differences do not exceed 10% in the aggregate, our reserve auditor is 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, who reports directly to our Chairman, President and Chief Executive Officer. Mr. Alan Farquharson, 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.

The SEC defines proved reserves as those volumes of natural gas, NGLs, crude oil and condensate 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 those proved reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves can only be assigned to acreage for which improved recovery technology is contemplated when such techniques have been proven effective by actual tests in the area and in the same reservoir. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating each location is scheduled to be drilled within five years from the date it was booked as proved reserves, unless specific circumstances justify a longer time.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The average realized prices used at December 31, 2015 to estimate reserve information were $35.07 per barrel of oil, $11.74 per barrel of NGLs and $2.07 per mcf for gas using a benchmark (NYMEX) of $50.13 per barrel and $2.59 per Mmbtu. The average realized prices used at December 31, 2014 to estimate reserve information were $79.04 per barrel of oil, $27.20 per barrel of NGLs and $4.14 per mcf for gas, using a benchmark (NYMEX) of $94.42 per barrel and $4.35 per Mmbtu. The average realized prices used at December 31, 2013 to estimate reserve information were $86.66 per barrel of oil, $25.93 per barrel of NGLs and $3.75 per mcf for gas, using a benchmark (NYMEX) of $97.33 per barrel and $3.67 per Mmbtu.

	Natural Gas (Mmcf)	NGLs (Mbbls)	Crude Oil and Condensate (Mbbls)	Natural Gas Equivalents (Mmcfe) [a]
Proved developed and undeveloped reserves:				
Balance, December 31, 2012	4,792,676	240,399	45,082	6,505,570
Revisions	384,825	7,743	2,935	448,898
Extensions, discoveries and additions	853,746	135,810	10,723	1,732,944
Purchases	¾	¾	¾	¾
Property sales	(101,074)	(286)	(6,553)	(142,116)
Production	(264,528)	(9,254)	(3,827)	(343,022)
Balance, December 31, 2013	5,665,645	374,412	48,360	8,202,274
Revisions	(30,566)	19,716	515	90,822
Extensions, discoveries and additions	1,393,108	154,664	12,936	2,398,709
Purchases	262,813	¾	¾	262,813
Property sales	(81,238)	(14,064)	(9,083)	(220,122)
Production	(286,926)	(18,821)	(4,070)	(424,267)
Balance, December 31, 2014	6,922,836	515,907	48,658	10,310,229
Revisions	(340,286)	17,717	3,804	(211,163)
Extensions, discoveries and additions	1,017,956	36,308	4,924	1,265,348
Purchases	¾	¾	¾	¾
Property sales	(960,122)	(441)	(109)	(963,423)
Production	(362,687)	(20,356)	(4,084)	(509,328)
Balance, December 31, 2015	6,277,697	549,135	53,193	9,891,663
Proved developed reserves:				
December 31, 2013	2,797,483	206,477	26,054	4,192,666
December 31, 2014	3,583,051	270,271	24,180	5,349,761
December 31, 2015	3,376,165	309,306	31,679	5,422,075
Proved undeveloped reserves:				
December 31, 2013	2,868,162	167,935	22,306	4,009,608
December 31, 2014	3,339,785	245,636	24,478	4,960,468
December 31, 2015	2,901,533	239,828	21,514	4,469,588

[a] 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 to natural gas, which is not indicative of the relationship of oil and natural gas prices.

During 2015, we added approximately 1.3 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 80% of the 2015 reserve additions are attributable to natural gas. Included in 2015 proved reserves is a total of 292.8 Mmbbls of ethane reserves (1,296 Bcfe) in the Marcellus Shale. Revisions of previous estimates of a negative 211 Bcfe includes positive performance revisions and improved recoveries of 781.0 Bcf primarily from our Marcellus Shale natural gas properties more than offset by negative price revisions and 1.2 Tcfe reclassified to unproved because of lower future capital spending in response to lower commodity prices.

During 2014, we added approximately 2.4 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 58% of 2014 reserve additions were attributable to natural gas. Included in 2014 proved reserves is a total of 1,170 Bcfe of ethane reserves (264.3 Mmbbls) in the Marcellus Shale. Revisions of previous estimates of a positive 91 Bcfe includes positive performance revisions, improved recoveries of 449.6 Bcfe primarily from our Marcellus Shale natural gas properties and positive price revisions are somewhat offset by reserves of 611 Bcfe reclassified to unproved as we continue to see success from drilling longer laterals, increasing the number of frac stages and better lateral targeting which caused some previously planned wells to not be drilled within the original five-year development horizon.

During 2013, we added approximately 1.7 Tcfe of proved reserves from drilling activities and valuation of proved areas primarily in the Marcellus Shale. Approximately 49% of 2013 reserve additions were attributable to natural gas. Also, included in

2013 proved reserves is a total of 676 Bcfe of ethane reserves (155.8 Mmbbls) in the Marcellus Shale. Revisions of previous estimates of a positive 449 Bcfe includes positive performance revisions and improved recoveries of 630.3 Bcfe primarily from our Marcellus Shale natural gas properties and positive pricing revisions, somewhat offset by reserves reclassified to unproved because of a slower pace of development activity beyond the five-year development horizon.

The following details the changes in proved undeveloped reserves for 2015 (Mmcfe):

Beginning proved undeveloped reserves at December 31, 2014	4,960,468
Undeveloped reserves transferred to developed	(762,936)
Revisions [(a)]	(441,874)
Purchases/(sales)	(201,809)
Extension and discoveries	915,739
Ending proved undeveloped reserves at December 31, 2015	4,469,588

[(a)] Includes 1.2 Tcfe of proved undeveloped reserves dropped due to the five year rule which can be included in our future proved reserves as these locations are added back to our five-year development plan.

Approximately $398.8 million was spent during 2015 related to undeveloped reserves that were transferred to developed reserves. Estimated future development costs of proved undeveloped reserves are projected to be approximately $435.6 million in 2016, $509.4 billion in 2017 and $471.6 million in 2018. As of December 31, 2015, we have no proved undeveloped well locations that are scheduled to be drilled more than five years from their original date of booking. All proved undeveloped drilling locations are scheduled to be drilled prior to the end of 2020.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following summarizes the policies we used in the preparation of the accompanying natural gas, NGLs, crude oil and condensate reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas, NGLs and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of December 31 of the years presented. These estimates were prepared by our petroleum engineering staff. Proved reserves are estimated quantities of natural gas, NGLs, crude oil and condensate, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future amounts expected to be produced based on current year-end economic conditions.
2. For the years ended 2015, 2014 and 2013, estimated future cash inflows are calculated by applying a twelve-month average price of natural gas, NGLs and oil relating to our proved reserves to the quantities of those reserves produced in each future year.
3. 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 year-end economic conditions. Future income tax expenses are based on current year-end statutory tax rates giving effect to the remaining tax basis in the natural gas, NGLs and oil properties, other deductions, credits and allowances relating to our proved natural gas and oil reserves.

4. The resulting future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas, NGLs and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved natural gas, NGLs, crude oil and condensate reserves is as follows and excludes cash flows associated with derivatives outstanding at each of the respective reporting dates. Future cash inflows are net of third party transportation, gathering and compression expense.

	As of December 31,	
	2015	2014
	(in thousands)	
Future cash inflows	$21,290,873	$46,507,646
Future costs:		
Production	(10,411,360)	(15,239,210)
Development [(a)]	(2,213,582)	(4,275,693)
Future net cash flows before income taxes	8,665,931	26,992,743
Future income tax expense	(2,007,794)	(8,900,383)
Total future net cash flows before 10% discount	6,658,137	18,092,360
10% annual discount	(3,932,274)	(10,499,333)
Standardized measure of discounted future net cash flows	$2,725,863	$7,593,027

[(a)] 2015 includes $384.5 million of undiscounted future asset retirement costs estimated as of December 31, 2015, using current estimates of future abandonment costs.

The following table summarizes changes in the standardized measure of discounted future net cash flows.

	December 31,		
	2015	2014	2013
	(in thousands)		
Revisions of previous estimates:			
Changes in prices and production costs	$(7,231,629)	$5,069	$2,172,704
Revisions in quantities	(868,886)	102,760	513,168
Changes in future development and abandonment costs	359,540	(407,688)	(275,468)
Net change in income taxes	2,173,904	(441,935)	(1,299,227)
Accretion of discount	1,007,027	789,754	395,989
Purchases of reserves in place	¾	297,358	¾
Additions to proved reserves from extensions, discoveries and improved recovery	486,478	2,713,999	1,981,054
Natural gas, NGLs and oil sales, net of production costs	(522,682)	(1,391,663)	(1,286,103)
Development costs incurred during the period	1,033,539	755,384	462,862
Sales of reserves in place	(1,050,237)	(249,055)	(162,463)
Timing and other	(254,218)	(443,187)	135,910
Net change for the year	(4,867,164)	1,730,796	2,638,426

Beginning of year	7,593,027	5,862,231	3,223,805
End of year	$2,725,863	$7,593,027	$5,862,231

RANGE RESOURCES CORPORATION

INDEX TO EXHIBITS

Exhibit Number	Exhibit Description
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004) as amended by the Certificate of First Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005 and the Certificate of Second Amendment to the Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 24, 2008)
3.2	Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 20, 2010)
4.1	Form of 5.75% Senior Subordinated Notes due 2021 (incorporated by reference to Exhibit A to Exhibit 4.2 on Form 8-K (File No. 001-12209) as filed with the SEC on May 25, 2011)
4.2	Indenture dated May 25, 2011 by and among Range, as issuer, the Subsidiary Guarantors (as defined therein), as guarantors and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on May 25, 2011)
4.3	Form of 5.00% Senior Subordinated Notes due 2022 (incorporated by reference to Exhibit A to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 9, 2012)
4.4	Indenture dated March 9, 2012 by and among Range, as issuer, the Subsidiary Guarantors (as defined therein), as guarantors and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 9, 2012)
4.5	Form of 5.00% Senior Subordinated Notes due 2023 (incorporated by reference to Exhibit A to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 19, 2013)
4.6	Indenture dated March 18, 2013 among Range Resources Corporation, as issuer, the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 19, 2013)

4.7	Form of 4.875% Senior Notes due 2025 (incorporated by reference to Exhibit A to Exhibit 4.1 on Form 8-K (File No. 001-12009) as filed with the SEC on May 14, 2015)
4.8	Indenture dated May 14, 2015 among Range Resources Corporation, as issuer, the Initial Guarantors (as defined therein) and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on May 14, 2015)
4.9	Registration Rights Agreement dated May 14, 2015 among Range Resources Corporation, the Initial Guarantors (as defined therein) and the Representatives (as defined therein) (incorporated by reference to Exhibit 4.2 on our Form 8-K (File No. 001-12209) as filed with the SEC on May 14, 2015)
10.01	Fifth Amended and Restated Credit Agreement, dated as of October 16, 2014 among Range (as borrowers) and JPMorgan Chase Bank, N.A. and the institutions named (therein) as lenders, JPMorgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on October 20, 2014)
10.02	First Amendment to the Fifth Amended and Restated Credit Agreement among Range Resources Corporation (as borrower) and the institutions named therein as lenders. JPMorgan Chase Bank, N.A. as Administrative Agent incorporated by reference to Exhibit 99.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on April 1, 2015)
10.03	Amended and Restated Range Resources Corporation 2004 Deferred Compensation Plan for Directors and Select Employees effective December 31, 2008 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on December 5, 2008)
10.04	Range Resources Corporation Amended and Restated 2005 Equity Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on June 4, 2009)

Exhibit Number	Exhibit Description
10.05	First Amendment to the Range Resources Corporation Amended and Restated 2005 Equity Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 20, 2010)
10.06	Second Amendment to the Range Resources Corporation Amended and Restated 2005 Equity Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 19, 2011)
10.07	Range Resources Corporation 401(k) Plan (incorporated by reference to Exhibit 10.14 to our Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)
10.08	Amended and Restated Range Resources Corporation Executive Change in Control Severance Benefit Plan effective December 31, 2008 (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on December 5, 2008)
10.09	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.6 to our Form 8-K (File No. 001-12209) as filed with the SEC on February 17, 2009)
21.1*	Subsidiaries of Registrant
23.1*	Consent of Independent Registered Public Accounting Firm
23.2*	Consent of Wright and Company, independent consulting engineers
31.1*	Certification by the Chairman and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification by the Chairman and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

32.2**	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Wright and Company, independent consulting engineers
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.
** Furnished herewith.