SANDRIDGE ENERGY INC
Form 10-K
March 30, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
þ 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: 001-33784
SANDRIDGE ENERGY, INC.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Delaware<br>(State or other jurisdiction of<br>incorporation or organization) | 20-8084793<br>(I.R.S. Employer<br>Identification No.) |
| 123 Robert S. Kerr Avenue<br>Oklahoma City, Oklahoma<br>(Address of principal executive offices) | 73102<br>(Zip Code) |

(405) 429-5500
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| Common Stock, $0.001 par value | New York Stock Exchange |

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No þ
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 þ
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 þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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 þ 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. þ

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 o | Accelerated filer þ |
| Non-accelerated filer o (Do not check if smaller reporting company) | Smaller reporting company o |

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2015 was approximately $447.7 million based on the closing price as quoted on the New York Stock Exchange. As of March 23, 2016, there were 718,226,053 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company’s definitive proxy statement for the 2016 Annual Meeting of Stockholders are incorporated by reference in Part III.

SANDRIDGE ENERGY, INC.
2015 ANNUAL REPORT ON FORM 10-K
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Certain Defined Terms

References in this report to the "Company" and "SandRidge" mean SandRidge Energy, Inc., including its consolidated subsidiaries and variable interest entities of which it is the primary beneficiary. In addition, this report includes terms commonly used in the oil and natural gas industry, which are defined in the "Glossary of Oil and Natural Gas Terms" beginning on page 26.

Information Regarding Forward-Looking Statements

Various statements contained in this report, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These statements generally are accompanied by words that convey projected future events or outcomes. These forward-looking statements may include projections and estimates concerning the Company's capital expenditures, liquidity, capital resources and debt profile, pending dispositions, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, elements of the Company's business strategy, compliance with governmental regulation of the oil and natural gas industry, including environmental regulations, acquisitions and divestitures and the effects thereof on the Company's financial condition and other statements concerning the Company's operations, financial performance and financial condition. Forward-looking statements are generally accompanied by words such as "estimate," "assume," "target," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal," "should," "intend" or other words that uncertainty of future events or outcomes. The Company has based these forward-looking statements on its current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments as well as other factors the Company believes are appropriate under the circumstances. The actual results or developments anticipated may not be realized or, even if substantially realized, may not have the expected consequences to or effects on the Company's business or results. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in such forward-looking statements. These forward-looking statements speak only as of the date hereof. The Company disclaims any obligation to update or revise these forward-looking statements unless required by law, and it cautions readers not to rely on them unduly. While the Company's management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks and uncertainties discussed in "Risk Factors" in Item 1A of this report, including the following:

- risks associated with drilling oil and natural gas wells;
- the volatility of oil, natural gas and natural gas liquids ("NGL") prices;
- uncertainties in estimating oil, natural gas and NGL reserves;
- the need to replace the oil, natural gas and NGLs the Company produces;
- the Company's ability to execute its growth strategy by drilling wells as planned;
- the amount, nature and timing of capital expenditures, including future development costs, required to develop the Company's undeveloped areas;
- concentration of operations in the Mid-Continent region of the United States;
- risks associated with obligations to deliver minimum volumes of natural gas under long-term contracts, including the risk that the Company will incur significant monetary penalties for under-delivery;
- limitations of seismic data;
- the potential adverse effect of commodity price declines on the carrying value of the Company's oil and natural properties;
- severe or unseasonable weather that may adversely affect production;

- availability of satisfactory oil, natural gas and NGL marketing and transportation;
- availability and terms of capital to fund capital expenditures;
- amount and timing of proceeds of asset monetizations;
- substantial existing indebtedness and limitations on operations resulting from debt restrictions and financial covenants;
- potential financial losses or earnings reductions from commodity derivatives;
- potential elimination or limitation of tax incentives;
- competition in the oil and natural gas industry;
- general economic conditions, either internationally or domestically or in the areas where the Company operates;

- costs to comply with current and future governmental regulation of the oil and natural gas industry, including environmental, health and safety laws and regulations, and regulations with respect to hydraulic fracturing and the disposal of produced water; and
- the need to maintain adequate internal control over financial reporting.

# PART I

## Item 1. Business

### GENERAL

SandRidge Energy, Inc. is an energy company engaged in the exploration, development and production of crude oil, natural gas and NGLs. The Company's primary area of operation is the Mid-Continent in Oklahoma and Kansas. The Company owns and operates additional interests in west Texas and acquired properties located in the Rockies in Colorado in December 2015. Additionally, the Company owned interests in the Gulf of Mexico and Gulf Coast until February 2014, as discussed under "2014 Divestiture" below.

As of December 31, 2015, the Company had 4,411 gross (3,371.7 net) producing wells, a substantial portion of which it operates, and approximately 2,063,000 gross (1,476,000 net) total acres under lease. As of December 31, 2015, the Company had four rigs drilling in the Mid-Continent. Total estimated proved reserves as of December 31, 2015 were 324.6 MMBoe, of which approximately 80% were proved developed.

The Company also operates businesses and infrastructure systems that are complementary to its primary exploration and production activities, including gas gathering and processing facilities, marketing operations, a saltwater gathering and disposal system and an electrical transmission system. Additionally, until January 2016, the Company operated a drilling and related oilfield services business.

The Company's principal executive offices are located at 123 Robert S. Kerr Avenue, Oklahoma City, Oklahoma 73102 and the Company's telephone number is (405) 429-5500. SandRidge makes available free of charge on its website at www.sandridgeenergy.com its annual reports 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 the Company electronically files such material with, or furnishes it to, the Securities and Exchange Commission ("SEC"). Any materials that the Company has filed with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington D.C. 20549 or accessed via the SEC's website address at www.sec.gov.

### Business Strategy

SandRidge's mission is to become a high-return, growth-oriented resource conversion company focused in the Mid-Continent and Rockies regions of the United States. In pursuit of its mission, the Company focuses on the following strategies:
Complementary Operating Areas. The Company's primary areas of operation are the Mid-Continent area of Oklahoma and Kansas and the Niobrara Shale in the Colorado Rockies. In the Mid-Continent, the Company is able to (i) increase its technical expertise that it has developed as one of the most active drillers and operators in the region and leverage that expertise in the interpretation of geological and operational opportunities, (ii) achieve economies of scale and breadth of operations, both of which help to control costs, (iii) take advantage of investments in infrastructure including electrical delivery and saltwater gathering and disposal systems and (iv) opportunistically grow its holdings through acquisitions, farmouts and operations in this area to achieve production and reserve growth. With the recent acquisition of Rockies acreage and assets in Colorado's North Park Basin, the Company intends to develop a proven oil resource play similar to that being developed in Colorado's DJ Basin, both areas drawing from the oil rich Niobrara Shale. In the Rockies, the Company intends to apply its core competencies in developing medium depth formations and deploy its expertise in multi-stage fracture stimulation, artificial lift and extended and multi-lateral wellbore designs. Additionally, as operator of a majority of its wells, the Company has flexibility to utilize these competitive advantages to deliver strong, sustainable returns.

Preservation of Capital in Depressed Commodity Pricing Environment. Volatility of pricing can significantly impact the amount of revenue received for oil and natural gas production and the level of economic returns the Company receives for amounts invested in its exploration and development activities. Over time, costs to drill, complete and operate wells typically adjust to prevailing commodity price levels, resulting in improved and more certain returns; however, during periods of depressed oil and natural gas pricing, such as that which began during the second half of 2014 and is continuing, the Company preserves capital and liquidity by contracting its capital expenditures budget and high-grading locations for development. During such times, the Company capitalizes on in place infrastructure, such as the Company’s saltwater gathering and disposal and electrical systems, by focusing drilling efforts on locations that can most effectively make use of this existing infrastructure. Additionally, exploration programs are conducted within a high-graded inventory of locations that have a greater certainty of economic returns. The Company’s 2016 capital expenditures budget is approximately $285.0 million, with approximately $262.0 million designated for exploration and production activities.

Focus on Cost Efficiency and Capital Allocation. By leveraging its experienced workforce, scalable operational structure and infrastructure systems, the Company is able to achieve cost efficiencies and sustainable returns in the Mid-Continent and Niobrara Shale in the Rockies. In the Mid-Continent, with a focus on lower-risk, high rate of return and repeatable drilling opportunities with long economic lives, the Company has made improvements in its multi-lateral wellbore designs, its completion designs, well site production facilities, utilization of pad drilling, its vendor contracts and spud-to-spud cycle time to further reduce its cost structure in the Mid-Continent. Further, due to the low pressure and shallow characteristics of the reservoirs the Company develops, the Company is able to maintain a low-cost operating structure and manage service costs. Similar opportunities exist in the development of the Niobrara Shale in the Rockies, where technologies developed in the Mid-Continent are transferable. The ability to drill multiple laterals from a single pad or single vertical wellbore is expected to facilitate cost-effective development of this oil rich resource play.

Mitigate Commodity Price Risk. As appropriate, the Company enters into derivative contracts to mitigate a portion of the commodity price volatility inherent in the oil and natural gas industry. By increasing the predictability of cash inflows for a portion of its future production, the Company is better able to mitigate funding risks for its longer term development plans and lock-in rates of return on its capital projects.

Develop Key Infrastructure Systems. By constructing a saltwater gathering and disposal system and electrical delivery system to service its Mid-Continent properties, the Company is able to produce oil and natural gas more efficiently and, therefore, more economically, giving it a competitive advantage over other operators in this rural area. Expertise developed by the Company in planning and executing large scale infrastructure and midstream projects in the Mid-Continent is being directly applied to the development of the Niobrara Shale.

Maintain Flexibility. The Company has multi-year inventories of both oil and natural gas drilling locations within its core operating area. Maintaining inventories of both oil and natural gas drilling locations allows the Company to efficiently direct capital toward projects with the most attractive returns.

Pursue Opportunistic Acquisitions. The Company periodically reviews acquisition targets to complement its existing asset base. The Company selectively identifies such targets based on several factors including relative value, hydrocarbon mix and location, and the relative fit of the Company's core competencies and technical expertise and, when appropriate, seeks to acquire them at a discount to other opportunities.

Acquisitions and Divestitures

2016 Divestiture and Release from Treating Agreement

On January 21, 2016, the Company transferred ownership of substantially all of its oil and natural gas properties and midstream assets located in the Piñon field in the West Texas Overthrust ("WTO") and $11.0 million in cash to a wholly owned subsidiary of Occidental Petroleum Corporation ("Occidental") and was released from all past, current and future claims and obligations under an existing 30-year treating agreement between the companies. For the year ended December 31, 2015, production, revenues and direct operating expenses for the conveyed oil and natural gas properties were 1.9 MMBoe, $14.6 million and $41.1 million, respectively. Additionally, during the year ended December 31, 2015, the Company accrued approximately $34.9 million in penalties related to the Company's shortfall in meeting its 2015 annual $CO_2$ delivery requirement under the 30-year treating agreement that was terminated in accordance with the terms of the transaction.

The assets of Piñon Gathering Company, LLC ("PGC"), which were acquired by the Company in October 2015 as discussed further below, were included in the consideration conveyed to Occidental.

2015 Acquisitions

Piñon Gathering Company, LLC. In October 2015, the Company acquired the assets of and terminated a gas gathering agreement with PGC for $48.0 million in cash and $78.0 million principal amount of newly issued 8.75% Senior

Secured Notes due 2020 (“Senior Secured Notes”). PGC owns approximately 370 miles of gathering lines supporting the natural gas production from the Company's Piñon field in the WTO.

Rockies Properties - North Park Basin. In December 2015, the Company acquired approximately 135,000 net acres in the North Park Basin, Jackson County, Colorado for approximately $191.1 million in cash, including post-closing adjustments. Also included in the acquisition were working interests in 16 wells previously drilled on the acreage. Additionally, the seller paid the Company $3.1 million for certain overriding interests retained in the properties.

2014 Divestiture

Sale of Gulf of Mexico and Gulf Coast Properties. On February 25, 2014, the Company sold certain of its subsidiaries that owned the Company’s Gulf of Mexico and Gulf Coast oil and natural gas properties (collectively, the “Gulf Properties”), to Fieldwood Energy, LLC (“Fieldwood”) for $702.6 million, net of working capital adjustments and post-closing adjustments, and Fieldwood’s assumption of approximately $366.0 million of related asset retirement obligations. The Company used the proceeds from the sale to fund its drilling in the Mid-Continent. Additionally, the Company settled a portion of its existing oil derivative contracts in January and February 2014 prior to their respective maturities to reduce volumes hedged in proportion to the anticipated reduction in daily production volumes due to the sale, which resulted in the Company making cash payments of approximately $69.6 million. The Company retained a 2% overriding royalty interest in certain exploration prospects.

In accordance with the terms of the sale, the Company agreed to guarantee on behalf of the buyer certain plugging and abandonment obligations associated with the Gulf Properties for a period of up to one year from the date of closing. Additionally, the buyer agreed to indemnify the Company for any costs it may incur as a result of the guarantee. The Company did not incur any costs as a result of this guarantee, and was released from the obligation during the third quarter of 2015.

2013 Divestiture

Sale of Permian Properties. On February 26, 2013, the Company sold its oil and natural gas properties in the Permian Basin area of west Texas, excluding the assets associated with the SandRidge Permian Trust area of mutual interest (the “Permian Properties”) for net proceeds of $2.6 billion, including post-closing adjustments that were finalized in the third quarter of 2013. The Company used a portion of the sale proceeds to fund the redemption of approximately $1.1 billion aggregate principal amount of outstanding senior notes and used the remaining proceeds to fund capital expenditures in the Mid-Continent and for general corporate purposes. Including final post-closing adjustments, the Company recorded a non-cash loss on the sale of $398.9 million, of which $71.7 million was allocated to noncontrolling interests. Additionally, the Company settled a portion of its existing oil derivative contracts in February 2013 prior to their contractual maturities to reduce volumes hedged in proportion to the anticipated reduction in daily production volumes due to the sale, which resulted in a loss on settlement of approximately $29.6 million.

PRIMARY BUSINESS OPERATIONS

The Company’s dominant segment is its exploration and production business, which explores for, develops and produces oil and natural gas. Financial information for this segment and the Company’s two other reportable business segments, the drilling and oilfield services and midstream services segments, is provided in Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Note 23—Business Segment Information” to the Company’s consolidated financial statements in Item 8 of this report. The information below includes the interests and activities of SandRidge Mississippian Trust I (the “Mississippian Trust I”), SandRidge Permian Trust (the “Permian Trust”) and SandRidge Mississippian Trust II (the “Mississippian Trust II”) (collectively, the “Royalty Trusts”), including amounts attributable to noncontrolling interest, all of which are included in the exploration and production segment.

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The following table presents information concerning the Company's exploration and production activities by geographic area of operation as of December 31, 2015, unless otherwise noted.

| Area | Estimated Net Proved Reserves (MMBoe) | PV-10 (In millions)(1) | Daily Production (MBoe/d)(2) | Reserves/ Production (Years)(3) | Gross Acreage | Net Acreage | Capital Expenditures (In millions) (4) |
|---|---|---|---|---|---|---|---|
| Mid-Continent | 259.1 | $ 1,171.8 | 59.5 | 11.9 | 1,826,050 | 1,273,232 | $ 655.4 |
| Rockies | 27.6 | 18.4 | 0.5 | — | 148,509 | 134,933 | — |
| West Texas | 37.9 | 124.8 | 8.3 | 12.5 | 88,244 | 68,210 | 4.9 |
| Total | 324.6 | $ 1,315.0 | 68.3 | 13.0 | 2,062,803 | 1,476,375 | $ 660.3 |

(1) For a reconciliation of PV-10 to Standardized Measure, see "—Proved Reserves." The Company's total Standardized Measure was $1.3 billion at December 31, 2015.
(2) Average daily net production for the month of December 2015.
(3) Estimated net proved reserves as of December 31, 2015 divided by production for the month of December 2015 annualized.
(4) Capital expenditures for the year ended December 31, 2015 on an accrual basis.

Properties

Mid-Continent

The Company held interests in approximately 1,826,000 gross (1,273,000 net) leasehold acres primarily in Oklahoma and Kansas at December 31, 2015. Associated proved reserves at December 31, 2015 totaled 259.1 MMBoe, 85% of which were proved developed reserves, based on estimates prepared by Cawley, Gillespie & Associates, Inc., ("CG&A") and the Company's internal engineers. The Company's interests in the Mid-Continent as of December 31, 2015 included 2,386 gross (1,392.2 net) producing wells with an average working interest of 59%. The Company had four rigs operating in the Mid-Continent as of December 31, 2015, all of which were drilling horizontal wells. The Company drilled a total of 165 wells in this area during 2015, of which 161 were horizontal wells and four were saltwater disposal wells.

Mississippian Formation. A key target for exploration and development within the Mid-Continent area is the Mississippian formation, which is an expansive carbonate hydrocarbon system located on the Anadarko Shelf in northern Oklahoma and southern Kansas. The top of this formation is encountered between approximately 4,000 and 7,000 feet and lies stratigraphically between various formations of Pennsylvanian age and the Devonian-aged Woodford Shale formation. The Mississippian formation can reach 1,000 feet in gross thickness and have targeted porosity zone(s) ranging between 20 and 150 feet in thickness. At December 31, 2015, the Company had approximately 1,732,000 gross (1,218,000 net) acres under lease in the Mississippian formation.

The Company has drilled approximately 1,675 wells in this formation as of December 31, 2015. From December 31, 2014 to December 31, 2015, the number of the Company's producing horizontal wells in the Mississippian formation increased from 1,555 to 1,726. Of the wells the Company drilled in the Mississippian formation during 2015, three wells are subject to the royalty interests of the Mississippian Trust II. The Company fulfilled its drilling obligation to the Mississippian Trust II in March 2015.

Other Formations. The Company drilled 23 wells in the Chester formation and eight wells in the Woodford formation in 2015 in order to determine commerciality and initiate development of these productive formations.

Historically drilled with vertical wells, the Chester formation in the Northern Mid-Continent is currently being targeted for horizontal development. The formation, which lies beneath various Pennsylvanian-aged formations and above the Mississippian formation, is composed of stacked low permeability sandstone and carbonate layers interbedded with shale. The top of the formation occurs at about 5,600 feet and ranges in thickness from less than 100 to over 1,000 feet. Individual target zones within the formation range from 15 to 50 feet in thickness.

Long regarded as the primary source rock for most Mid-Continent reservoirs, the Woodford formation is now itself being developed horizontally across much of Oklahoma. This Devonian-aged formation, which lies beneath the Mississippian formation and above various Lower Paleozoic formations, is stratigraphically equivalent to the Marcellus Shale in the

Appalachian Basin and the Bakken Shale in the Williston Basin. It is composed of alternating layers of organic-rich shale and less organic-rich siliceous or carbonate-rich shale. The top of the formation in the exploration and development area ranges from 6,200 to 10,000 feet, and the thickness of the formation ranges from less than 50 to over 100 feet.
Gathering and Disposal and Electrical Systems. The Company's electrical infrastructure, owned by the Company's midstream services segment, and saltwater gathering and disposal system assist in the economically efficient production of oil and natural gas in the Mid-Continent. The Company's electrical infrastructure, which consisted of approximately 1,122 miles of power lines and seven substations at December 31, 2015, coordinates the delivery of electricity to the Company's Mid-Continent operations at a lower cost than electricity provided by on-site generation. Additionally, by building its own infrastructure in these rural areas, the Company has been able to provide sufficient electricity to its operations. The Company is also able to obtain lower electrical rates based on aggregated volumes. The saltwater gathering and disposal system, which included more than 150 active wells and approximately 1,150 miles of gathering lines at December 31, 2015, reduces the overall cost of water disposal, which directly reduces production costs. The system has a current injection capacity of over 2.0 million barrels of water per day.
Rockies
The Company acquired its Rockies assets, located in the North Park Basin in Jackson County, Colorado, in December 2015. At December 31, 2015, the properties consisted of approximately 149,000 gross (135,000 net) acres and operated working interests in 16 previously drilled producing wells with an average working interest of 100%. Associated proved reserves at December 31, 2015 were approximately 27.6 MMBoe, of which approximately 6% were proved developed reserves. The Rockies acreage is located within the Niobrara Shale play. The Niobrara Shale is characterized by numerous stacked pay reservoirs at depths of 5,500 to 9,000 feet with reservoir thickness over 450 feet.

West Texas

The Company's west Texas oil and natural gas properties include properties in the WTO and the Permian Basin. As of December 31, 2015, the Company's west Texas properties consisted of approximately 88,000 gross (68,000 net) leasehold acres, 2,009 gross (1,963.5 net) producing wells with an average working interest of 98%. Associated proved reserves at December 31, 2015 were 37.9 MMBoe, 100% of which were proved developed reserves. The Company did not drill any wells in this area during 2015.

As discussed in "2016 Divestiture and Release from Treating Agreement" above, the Company divested its WTO oil and natural gas properties in January 2016. Also, under the terms of the transaction, the Company was released from its past, current and future obligations under a 30-year treating agreement pursuant to which (i) the Company delivered natural gas produced in the WTO to Occidental's $CO_2$ treatment plant in Pecos County, Texas (the "Century Plant") and (ii) Occidental removed $CO_2$ from natural gas volumes delivered by the Company. The Company retained all methane gas after treatment. Under the agreement, the Company was required to deliver a total of approximately 3,200 Bcf of $CO_2$ during the agreement period. The Company was obligated to pay Occidental \$0.25 per Mcf to the extent minimum annual $CO_2$ volume requirements were not met and \$0.70 per Mcf to the extent the total contract delivery requirement was not met by the end of the contract term.

Proved Reserves

Preparation of Reserves Estimates

The estimates of oil, natural gas and NGL reserves in this report are based on reserve reports, the substantial majority of which were prepared by independent petroleum engineers. To achieve reasonable certainty, the Company's engineers relied on technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used to estimate the Company's proved reserves include, but are not limited to, well logs, geological maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. This data was reviewed by various levels of management for accuracy, before consultation with independent petroleum engineers. Such consultation included review of properties, assumptions and any new data available. The Corporate Reservoir department's internal reserves estimates and methodologies were compared to those prepared by independent petroleum engineers to test the reserves estimates and conclusions before the reserves estimates were included in this report. The accuracy of the reserve estimates is dependent on many factors, including the following:

- the quality and quantity of available data and the engineering and geological interpretation of that data;

- estimates regarding the amount and timing of future costs, which could vary considerably from actual costs;

- the accuracy of economic assumptions such as the future price of oil and natural gas; and

- the judgment of the personnel preparing the estimates.

SandRidge’s Senior Vice President—Corporate Reservoir Engineering is the technical professional primarily responsible for overseeing the preparation of the Company’s reserves estimates. He has a Bachelor of Science degree in Petroleum Engineering with over 30 years of practical industry experience, including over 30 years of estimating and evaluating reserve information. He has also been a certified professional engineer in the state of Oklahoma since 2007 and a member of the Society of Petroleum Engineers since 1980.

SandRidge’s Reservoir Engineering Department continually monitors asset performance, making reserves estimate adjustments, as necessary, to ensure the most current reservoir information is reflected in reserves estimates. Reserve information includes production histories as well as other geologic, economic, ownership and engineering data. The Corporate Reservoir department currently has a total of 20 full-time employees, comprised of 11 degreed engineers and nine engineering and business analysts with a minimum of a four-year degree in mathematics, finance or other business or science field.

The Company maintains a continuous education program for its engineers and analysts on new technologies and industry advancements and also offers refresher training on basic skill sets.

In order to ensure the reliability of reserves estimates, internal controls within the reserve estimation process include:

- no employee’s compensation is tied to the amount of reserves recorded.
- reserves estimates are prepared by experienced reservoir engineers or under their direct supervision.
- the Senior Vice President—Corporate Reservoir Engineering reports directly to the Company’s Chief Operating Officer.
- the Reservoir Engineering Department follows comprehensive SEC-compliant internal policies to determine and report proved reserves including:
- confirming that reserves estimates include all properties owned and are based upon proper working and net revenue interests;
- reviewing and using in the estimation process data provided by other departments within the Company such as Accounting; and
- comparing and reconciling the Corporate Reservoir department’s internally generated reserves estimates to those prepared by third parties.

Each quarter, the Senior Vice President—Corporate Reservoir Engineering presents the status of the Company’s reserves to a committee of executives, which subsequently approves all changes.

The Reservoir Engineering Department works closely with its independent petroleum consultants at each fiscal year end to ensure the integrity, accuracy and timeliness of annual independent reserves estimates. These independently developed reserves estimates are reviewed by the Audit Committee, as well as the Chief Financial Officer, Senior Vice President of Accounting, Director of Internal Audit, Vice President of Financial Reporting and General Counsel and are approved as the Company’s corporate reserves. In addition to reviewing the independently developed reserve reports, the Audit Committee annually meets with the principal engineers who are primarily responsible for the reserve reports. The Audit Committee also periodically meets with the other independent petroleum consultants that prepare estimates of proved reserves.

The percentage of the Company’s total proved reserves prepared by each of the independent petroleum consultants is shown in the table below.

| | December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Cawley, Gillespie & Associates, Inc. | 77.7 % | 82.4 % | 64.6 % |
| Ryder Scott Company, L.P. | 8.5 % | — % | — % |
| Netherland, Sewell & Associates, Inc. | 3.9 % | 3.7 % | 21.5 % |
| Total | 90.1 % | 86.1 % | 86.1 % |

The remaining 9.9%, 13.9% and 13.9% of the Company’s estimated proved reserves as of December 31, 2015, 2014 and 2013, respectively, were based on internally prepared estimates.

Copies of the reports issued by the Company’s independent petroleum consultants with respect to the Company’s oil, natural gas and NGL reserves for the substantial majority of all geographic locations as of December 31, 2015 are filed with this report as Exhibits 99.1, 99.2 and 99.3. The geographic location of the Company’s estimated proved reserves prepared by each of the independent petroleum consultants as of December 31, 2015 is presented below.

| | Geographic Locations—by Area by State |
|---|---|
| Cawley, Gillespie & Associates, Inc. | Mid-Continent—KS, OK |
| Ryder Scott Company, L.P. | Rockies—CO |
| Netherland, Sewell & Associates, Inc. | Permian Basin—TX |

The qualifications of the technical personnel at each of these firms primarily responsible for overseeing the firm’s preparation of the Company’s reserves estimates included in this report are set forth below. These qualifications meet or exceed the Society of Petroleum Engineers’ standard requirements to be a professionally qualified Reserve Estimator and Auditor.

Cawley, Gillespie & Associates, Inc.
- more than 28 years of practical experience in petroleum engineering and more than 26 years of experience estimating and evaluating reserve information;
- a registered professional engineer in the state of Texas; and
- Bachelor of Science Degree in Petroleum Engineering.

Ryder Scott Company, L.P.
- more than 30 years of practical experience in the estimation and evaluation of petroleum reserves;
- a registered professional engineer in the states of Alaska, Colorado, Texas and Wyoming; and
- Bachelor of Science Degree in Petroleum Engineering and MBA in Finance;

Netherland, Sewell & Associates, Inc.
- practicing consulting petroleum engineering since 2013 and over 15 years of prior industry experience;
- licensed professional engineers in the state of Texas; and
- Bachelor of Science Degree in Chemical Engineering

Technologies

Under SEC rules, proved reserves are those quantities of oil, natural gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, based on prices used to estimate reserves, from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil, natural gas and/or NGLs actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil, natural gas or NGLs on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. In determining the amount of proved reserves, the price used must be the average price during the 12-month period prior to the ending date of the period covered by the reserve report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

The estimates of proved developed reserves included in the reserve report were prepared using decline curve analysis to determine the reserves of individual producing wells. After estimating the reserves of each proved developed well, it was determined that a reasonable level of certainty exists with respect to the reserves that can be expected from close offset undeveloped wells in the field.

Development Plan

Based on the economic conditions on December 31, 2015, the Company approved of a plan to develop the proved undeveloped locations identified in the Company’s reserve report within five years of initial booking, in accordance with SEC regulations. The reserve report anticipated a three rig drilling program for the first half of 2016 and four rigs in the second half of the year. Two rigs were scheduled to drill primarily proved undeveloped locations in the first half of 2016, increasing to three rigs in the second half of the year.

However, persistently low commodity prices through the first quarter of 2016 have negatively impacted the Company’s results of operations, financial condition and future development plans. As a result, the Company intends to scale back to a two rig drilling program beginning in the second quarter of 2016. If commodity pricing falls short of the Company's current expectations or rebounds to a level supportive of more drilling, the Company may change its 2016 capital expenditure plans again. However, the Company's management does not expect these short term changes to negatively impact the Company's ability to develop all of its December 31, 2015 proved undeveloped locations within the five year time frame described above, nor does it expect such changes to have a significant impact to the Company's overall development plan or PV-10 as presented in the Company's December 31, 2015 reserve report.

Reporting of Natural Gas Liquids

NGLs are produced as a result of the processing of a portion of the Company's natural gas production stream. At December 31, 2015, NGLs comprised approximately 19% of the Company's total proved reserves on a barrel equivalent basis and represented volumes to be produced from properties where the Company has contracts in place for the extraction and separate sale of NGLs. NGLs are products sold by the gallon. In reporting proved reserves and production of NGLs, the Company has included production and reserves in barrels. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. All production information related to natural gas is reported net of the effect of any reduction in natural gas volumes resulting from the processing and extraction of NGLs.

Reserve Quantities, PV-10 and Standardized Measure

The following estimates of proved oil, natural gas and NGL reserves are based on reserve reports as of December 31, 2015, 2014 and 2013, the substantial majority of which were prepared by independent petroleum engineers. The estimates include reserves attributable to the Royalty Trusts, including amounts associated with noncontrolling interest. The PV-10 values shown in the table below are not intended to represent the current market value of the Company's estimated proved reserves as of the dates shown. The reserve reports were based on the Company's drilling schedule and the average price during the 12-month periods ended December 31, 2015, 2014 and 2013, using first-day-of-the-month prices for each month. Such prices are not reflective of actual prices at December 31, 2015 or current prices. See further discussion of prices in "Risk Factors" included in Item 1A of this report. At December 31, 2015, the Company estimated that approximately 100% of its current proved undeveloped reserves will be developed by the end of 2020. See "Critical Accounting Policies and Estimates" in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates.

| | December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Estimated Proved Reserves(1) | | | |
| Developed | | | |
| Oil (MMBbls) | 48.6 | 79.0 | 83.9 |
| NGL (MMBbls) | 51.1 | 56.8 | 35.8 |
| Natural gas (Bcf) | 964.6 | 1,203.4 | 951.6 |
| Total proved developed (MMBoe) | 260.5 | 336.4 | 278.3 |
| Undeveloped | | | |
| Oil (MMBbls) | 29.3 | 47.0 | 58.7 |
| NGL (MMBbls) | 9.9 | 35.0 | 23.3 |
| Natural gas (Bcf) | 149.2 | 584.8 | 438.8 |
| Total proved undeveloped (MMBoe) | 64.1 | 179.5 | 155.1 |
| Total Proved | | | |
| Oil (MMBbls) | 77.9 | 126.0 | 142.6 |
| NGL (MMBbls) | 61.0 | 91.8 | 59.1 |
| Natural gas (Bcf) | 1,113.8 | 1,788.2 | 1,390.4 |
| Total proved (MMBoe)(2) | 324.6 | 515.9 | 433.4 |
| PV-10 (in millions)(3) | $1,315.0 | $5,516.4 | $5,191.6 |
| Standardized Measure of Discounted Net Cash Flows (in millions)(2)(4) | $1,314.6 | $4,087.8 | $4,017.6 |

(1) The Company's estimated proved reserves and the future net revenues, PV-10 and Standardized Measure were determined using prices calculated as a 12-month unweighted average of the first-day-of-the-month index price for each month of each year. All prices are held constant throughout the lives of the properties. The index prices and the equivalent weighted average wellhead prices used in the Company's reserve reports are shown in the table below.

| | Index prices (a) | | Weighted average wellhead prices (b) | | |
|---|---|---|---|---|---|
| | Oil (per Bbl) | Natural gas (per Mcf) | Oil (per Bbl)(c) | NGL (per Bbl) | Natural gas (per Mcf) |
| December 31, 2015 | $46.79 | $2.59 | $45.29 | $12.68 | $1.87 |
| December 31, 2014 | $91.48 | $4.35 | $91.65 | $32.79 | $3.61 |
| December 31, 2013 | $93.42 | $3.67 | $95.67 | $31.40 | $3.65 |

(a) Index prices are based on average West Texas Intermediate posted prices for oil and average Henry Hub spot market prices for natural gas.

(b) Average adjusted volume-weighted wellhead product prices reflect adjustments for transportation, quality, gravity, and regional price differentials.

(c) At December 31, 2013, the weighted average wellhead oil price is significantly higher than the index price as a result of favorable location differentials for production in the Gulf of Mexico.

(2) Estimated total proved reserves and Standardized Measure include amounts attributable to noncontrolling interests, as shown in the following table:

| | Estimated Proved Reserves (MMBoe) | Standardized Measure (In millions) |
|---|---|---|
| December 31, 2015 | 19.1 | $224.6 |
| December 31, 2014 | 27.6 | $643.3 |
| December 31, 2013 | 29.9 | $781.6 |

See “Note 25—Supplemental Information on Oil and Natural Gas Producing Activities” to the Company’s consolidated financial statements in Item 8 of this report for additional information regarding reserve and Standardized Measure amounts attributable to noncontrolling interests.

(3) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using 12-month average prices for the years ended December 31, 2015, 2014 and 2013. PV-10 differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of the Company’s oil and natural gas properties. PV-10 is used by the industry and by the Company’s management as a reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities. It is useful because its calculation is not dependent on the taxpaying status of the entity. The following table provides a reconciliation of the Company’s Standardized Measure to PV-10:

| | December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In millions) | | |
| Standardized Measure of Discounted Net Cash Flows | $1,314.6 | $4,087.8 | $4,017.6 |
| Present value of future income tax discounted at 10% | 0.4 | 1,428.6 | 1,174.0 |
| PV-10 | $1,315.0 | $5,516.4 | $5,191.6 |

(4) Standardized Measure represents the present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions used to calculate PV-10. Standardized Measure differs from PV-10 as Standardized Measure includes the effect of future income taxes.

Proved Reserves - Mid-Continent. Proved reserves in the Mid-Continent, primarily the Mississippian formation, increased from 302.3 MMBoe at December 31, 2013 to 454.4 MMBoe at December 31, 2014 and decreased to 259.1 MMBoe at December 31, 2015. The decrease in 2015 is primarily due to negative pricing revisions of approximately 185 MMBoe, predominantly associated with proved undeveloped reserves, and negative revisions of approximately 29 MMBoe due to well performance. These decreases were partially offset by 45 MMBoe of extensions due to successful drilling in the Mississippian formation. The proved reserves attributable to the Mid-Continent comprise a significant portion of the additions to the Company’s proved reserves for the three-year period. The reserves attributable to more than 1,700 producing wells and continuousness of the formation over the development area further support proved undeveloped classification of selective locations within close proximity to producing wells.

Proved Reserves - Rockies. The Company’s proved reserves in the Rockies, associated with the Niobrara Shale in the North Park Basin of Colorado, were acquired in December 2015 and totaled 27.6 MMBoe at December 31, 2015. The acquisition of these reserves provides an important proved reserve addition to the Company’s asset base. Reservoir characteristics of the Niobrara in the North Park Basin are similar to those of the Niobrara in the DJ Basin to the east of North Park. The reservoir consists of five stacked benches with proved reserves only booked to the D Bench of the Niobrara Shale. Proved developed reserves were booked based on 16 horizontal producing wells drilled in 14 sections across the play. Production performance and reservoir data gathered from the producing wells confirm consistency in reservoir properties such as porosity, thickness and stratigraphic conformity. These wells all encountered proven Niobrara D Bench reserves. Using the performance of the PDP wells, undeveloped reserves were booked for only the D bench of the Niobrara across 27 sections of the proved development area. Although well density in the DJ Basin Niobrara indicates increasing PUD density, the Company has only booked up to four wells per section for only the Niobrara D Bench.

Proved Reserves - West Texas. In 2015, proved reserves, net of production, decreased by 20.0 MMBoe, primarily due to pricing revisions as a result of significantly lower commodity prices. In 2014, proved reserves decreased by 9 MMBoe, primarily from revisions to proved undeveloped reserves in the Permian Basin, due largely to the removal of proved undeveloped drilling locations not expected to be drilled within a five year period.

Proved Undeveloped Reserves. The following table summarizes activity associated with proved undeveloped reserves during the periods presented:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Reserves converted from proved undeveloped to proved developed (MMBoe) | 15.8 | 31.4 | 44.6 |
| Drilling capital expended to convert proved undeveloped reserves to proved developed reserves (in millions) | $117.7 | $343.6 | $437.6 |

For the year ended December 31, 2015, the Company recognized a decrease in proved undeveloped reserves of 115 MMBoe, primarily due to negative revisions of approximately 147 MMBoe resulting from lower commodity prices. These negative revisions were partially offset by an addition to oil, natural gas and NGL reserves associated with proved undeveloped properties of 48 MMBoe for the year ended December 31, 2015. Reserves added from extensions and discoveries totaled 22 MMBoe, primarily from horizontal drilling in the Mississippian formation in the Mid-Continent, which includes 6 MMBoe of proved undeveloped reserves booked and converted during 2015. Acquisition of the Rockies assets, located in Jackson County, Colorado, in December 2015 added 26 MMBoe of proved undeveloped reserves. Approximately 10 MMBoe of proved undeveloped reserves at December 31, 2014 were converted to proved developed reserves during 2015.

Excluding asset sales, the Company recognized a net addition to oil, natural gas and NGL reserves associated with proved undeveloped properties of 73 MMBoe for the year ended December 31, 2014. Reserves added from extensions and discoveries totaled 67 MMBoe, primarily from horizontal drilling in the Mississippian formation in the Mid-Continent, which includes 10 MMBoe of proved undeveloped reserves booked and converted during 2014. Net positive revisions of 6 MMBoe were recognized and were comprised of 16 MMBoe in increases from the Mid-Continent primarily from an improved overall Mississippian proved undeveloped type curve, partially offset by negative 10 MMBoe revisions primarily from the removal of Permian Basin proved undeveloped drilling locations not expected to be drilled within a five year period. Approximately 21 MMBoe of proved undeveloped reserves at December 31, 2013 were converted to proved developed reserves during 2014.

Excluding asset sales, the Company recognized a net addition to oil, natural gas and NGL reserves associated with proved undeveloped properties of 42 MMBoe for the year ended December 31, 2013. Reserves added from extensions and discoveries totaled 67 MMBoe, primarily from horizontal drilling in the Mississippian formation in the Mid-Continent, which includes 10 MMBoe of proved undeveloped reserves booked and converted during 2013. These additions were offset by downward reserve revisions of 25 MMBoe, primarily from the Mississippian formation, due to the removal of proved undeveloped drilling locations not expected to be drilled within a five year period. These revisions were a result of the Company’s ongoing efforts to optimize its drilling plan within the Mississippian formation and reevaluating anticipated drilling locations. Approximately 35 MMBoe of proved undeveloped reserves at December 31, 2012 were converted to proved developed reserves during 2013.

For additional information regarding changes in the Company’s proved reserves during the three years ended December 31, 2015, 2014 and 2013 see “Note 25—Supplemental Information on Oil and Natural Gas Producing Activities” to the Company’s consolidated financial statements in Item 8 of this report.

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Significant Fields

Oil, natural gas and NGL production for fields containing more than 15% of the Company's total proved reserves at each year end are presented in the table below. The Mississippi Lime Horizontal field, which is located on the Anadarko Shelf in northern Oklahoma and Kansas and produces from the Mississippian formation, contained more than 15% of the Company's total proved reserves at December 31, 2015, 2014 and 2013.

| | Oil (MBbls) | NGL (MBbls) | Natural Gas (MMcf) | Total (MBoe) |
|---|---|---|---|---|
| Year Ended December 31, 2015 | | | | |
| Mississippi Lime Horizontal | 8,041 | 4,785 | 77,542 | 25,750 |
| Year Ended December 31, 2014 | | | | |
| Mississippi Lime Horizontal | 8,234 | 3,470 | 65,839 | 22,677 |
| Year Ended December 31, 2013 | | | | |
| Mississippi Lime Horizontal | 6,901 | 1,311 | 52,618 | 16,982 |

Mississippi Lime Horizontal Field. The Mississippi Lime Horizontal Field is located on the Anadarko Shelf in northern Oklahoma and Kansas and produces from the Mississippian formation. The Company's interests in the Mississippi Lime Horizontal Field as of December 31, 2015 included 1,773 gross (1,101.7 net) producing wells and a 62% average working interest in the producing area.

Production and Price History

The following tables set forth information regarding the Company's net oil, natural gas and NGL production and certain price and cost information for each of the periods indicated.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Production Data | | | |
| Oil (MBbls) | 9,600 | 10,876 | 14,279 |
| NGL (MBbls) | 5,044 | 3,794 | 2,291 |
| Natural gas (MMcf) | 92,105 | 85,697 | 103,233 |
| Total volumes (MBoe) | 29,995 | 28,953 | 33,776 |
| Average daily total volumes (MBoe/d) | 82.2 | 79.3 | 92.5 |
| Average Prices(1) | | | |
| Oil (per Bbl) | $45.83 | $89.86 | $97.58 |
| NGL (per Bbl) | $14.36 | $33.41 | $35.16 |
| Natural gas (per Mcf) | $2.12 | $3.70 | $3.36 |
| Total (per Boe) | $23.59 | $49.08 | $53.89 |

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(1) Prices represent actual average prices for the periods presented and do not include effects of derivative transactions.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Expenses per Boe | | | |
| Lease operating expenses | | | |
| Transportation | $1.51 | $1.23 | $1.29 |
| Processing, treating and gathering(1) | 0.88 | 1.16 | 1.05 |
| Other lease operating expenses(2) | 7.67 | 9.27 | 12.60 |
| Total lease operating expenses | $10.06 | $11.66 | $14.94 |
| Production taxes(3) | $0.51 | $1.10 | $0.96 |
| Ad valorem taxes | $0.23 | $0.29 | $0.35 |

(1) Includes costs attributable to gas treatment to remove $CO_2$ and other impurities from natural gas.

(2) The years ended December 31, 2015, 2014 and 2013 include $34.9 million, $33.9 million and $32.7 million, respectively, for amounts related to the Company's shortfall in meeting its annual $CO_2$ delivery obligations under a $CO_2$ treating agreement as described under "—Properties—West Texas" above.

(3) Net of severance tax refunds.

Productive Wells

The following table sets forth the number of productive wells in which the Company owned a working interest at December 31, 2015. The Company operates substantially all of its wells. Productive wells consist of producing wells and wells capable of producing, including oil wells awaiting connection to production facilities and natural gas wells awaiting pipeline connections to commence deliveries. Gross wells are the total number of producing wells in which the Company has a working interest and net wells are the sum of the Company's fractional working interests owned in gross wells.

| | Oil | | Natural Gas | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Area | | | | | | |
| Mid-Continent | 1,927 | 1,191.9 | 459 | 200.3 | 2,386 | 1,392.2 |
| Rockies | 16 | 16.0 | — | — | 16 | 16.0 |
| West Texas | 1,212 | 1,191.4 | 797 | 772.1 | 2,009 | 1,963.5 |
| Total | 3,155 | 2,399.3 | 1,256 | 972.4 | 4,411 | 3,371.7 |

Drilling Activity

The following table sets forth information with respect to wells the Company completed during the periods indicated. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of reserves found. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Gross wells refer to the total number of wells in which the Company had a working interest and net wells are the sum of the Company's fractional working interests owned in gross wells. As of December 31, 2015, the Company had 6 gross (3.8 net) operated wells drilling, completing or awaiting completion.

| | 2015 | | | | 2014 | | | | 2013 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Percent | Net | Percent | Gross | Percent | Net | Percent | Gross | Percent | Net | Percent |
| Completed Wells | | | | | | | | | | | | |
| Development | | | | | | | | | | | | |
| Productive | 167 | 100.0 % | 117.0 | 100.0 % | 626 | 97.5 % | 482.3 | 97.4 % | 607 | 98.1 % | 482.3 | 98.1 % |
| Dry | — | — % | — | — % | 16 | 2.5 % | 13.0 | 2.6 % | 12 | 1.9 % | 9.5 | 1.9 % |
| Total | 167 | 100.0 % | 117.0 | 100.0 % | 642 | 100.0 % | 495.3 | 100.0 % | 619 | 100.0 % | 491.8 | 100.0 % |
| Exploratory | | | | | | | | | | | | |
| Productive | 9 | 100.0 % | 7.0 | 100.0 % | 6 | 60.0 % | 4.6 | 60.5 % | 44 | 80.0 % | 31.0 | 79.3 % |
| Dry | — | — % | — | — % | 4 | 40.0 % | 3.0 | 39.5 % | 11 | 20.0 % | 8.1 | 20.7 % |
| Total | 9 | 100.0 % | 7.0 | 100.0 % | 10 | 100.0 % | 7.6 | 100.0 % | 55 | 100.0 % | 39.1 | 100.0 % |
| Total | | | | | | | | | | | | |
| Productive | 176 | 100.0 % | 124.0 | 100.0 % | 632 | 96.9 % | 486.9 | 96.8 % | 651 | 96.6 % | 513.3 | 96.7 % |
| Dry | — | — % | — | — % | 20 | 3.1 % | 16.0 | 3.2 % | 23 | 3.4 % | 17.6 | 3.3 % |
| Total | 176 | 100.0 % | 124.0 | 100.0 % | 652 | 100.0 % | 502.9 | 100.0 % | 674 | 100.0 % | 530.9 | 100.0 % |

The following table sets forth information with respect to all rigs operating on the Company's acreage as of December 31, 2015.

| | Owned | Third-Party | Total |
|---|---|---|---|
| Mid-Continent | 2 | 2 | 4 |

Developed and Undeveloped Acreage

The following table sets forth information regarding the Company's developed and undeveloped acreage at December 31, 2015:

| | Developed Acreage | | Undeveloped Acreage | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| Area | | | | |
| Mid-Continent | 686,600 | 453,290 | 1,139,450 | 819,942 |
| Rockies | 28,242 | 27,476 | 120,267 | 107,457 |
| West Texas | 54,221 | 49,681 | 34,023 | 18,529 |
| Total | 769,063 | 530,447 | 1,293,740 | 945,928 |

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage is established prior to such date, in which event the lease will remain in effect until production has ceased. The following table sets forth as of December 31, 2015, the expiration periods of the gross and net acres that are subject to leases in the undeveloped acreage summarized in the above table.

| | Acres Expiring | |
|---|---|---|
| | Gross | Net |
| Twelve Months Ending | | |
| December 31, 2016 | 570,696 | 414,282 |
| December 31, 2017 | 427,008 | 322,987 |
| December 31, 2018 | 64,472 | 43,022 |
| December 31, 2019 and later | 21,477 | 12,316 |
| Other(1) | 210,087 | 153,321 |
| Total | 1,293,740 | 945,928 |

(1) Leases remaining in effect until development efforts or production on the developed portion of the particular lease has ceased.

Included in the acreage due to expire during the twelve months ending December 31, 2016, as presented in the table above, are approximately 556,811 gross (405,648 net) acres in the Mid-Continent area. The Company has options to extend the leases on a portion of this acreage set to expire in the Mid-Continent in 2016 and expects to exercise such options or hold by production portions of such acreage where geological and engineering criteria deem it prudent to do so.

Marketing and Customers

The Company sells oil, natural gas and NGLs to a variety of customers, including utilities, oil and natural gas companies and trading and energy marketing companies. The Company had two customers that individually accounted for more than 10% of its total revenue during 2015. See “Note 23—Business Segment Information” to the Company’s consolidated financial statements in Item 8 of this report for additional information on its major customers. The number of readily available purchasers for the Company’s products makes it unlikely that the loss of a single customer in the areas in which the Company sells its products would materially affect its sales. The Company does not have any material commitments to deliver fixed and determinable quantities of oil and natural gas in the future under existing sales contracts or sales agreements.

Title to Properties

As is customary in the oil and natural gas industry, the Company initially conducts a preliminary review of the title to its properties for which it does not have proved reserves. Prior to the commencement of drilling operations on those properties, the Company conducts a thorough title examination and performs curative work with respect to significant defects. To the extent drilling title opinions or other investigations reflect title defects on those properties, the Company is typically responsible for curing any title defects at its expense. The Company generally will not commence drilling operations on a property until it has cured any material title defects on such property. In addition, prior to completing an acquisition of producing oil and natural gas leases, the Company performs title reviews on the most significant leases, and depending on the materiality of properties, the Company may obtain a drilling title opinion or review previously obtained title opinions. To date, the Company has obtained drilling title opinions on substantially all of its producing properties and believes that it has good and defensible title to its producing properties. The Company’s oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens, which the Company believes do not materially interfere with the use of, or affect its carrying value of, the properties.

COMPETITION

The Company believes that its leasehold acreage position, midstream assets, geographic concentration of operations and technical and operational capabilities enable it to compete effectively with other exploration and production operations. However, the oil and natural gas industry is intensely competitive.

The Company competes with major oil and natural gas companies and independent oil and natural gas companies for leases, equipment, personnel and markets for the sale of oil, natural gas and NGLs. Many of these competitors are financially stronger than the Company, but even financially troubled competitors can affect the market because of their need to sell oil, natural gas and NGLs at any price to maintain cash flow. Certain companies may be able to pay more for producing properties and undeveloped acreage. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil, natural gas and NGL prices. The Company's larger or fully integrated competitors may be able to absorb the burden of existing and any future federal, state and local laws and regulations more easily than the Company can, which would adversely affect its competitive position. The Company's ability to acquire additional properties and to discover reserves in the future depends on its ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because the Company has fewer financial and human resources than many companies in its industry, the Company may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Oil, natural gas and NGLs compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil, natural gas and NGLs or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil, natural gas and NGLs.

SEASONAL NATURE OF BUSINESS

Generally, demand for oil and natural gas decreases during the summer months and increases during the winter months. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit the Company's drilling and producing activities and other oil and natural gas operations in a portion of its operating areas. These seasonal anomalies can pose challenges for meeting the Company's well drilling objectives, can delay the installation of production facilities, and can increase competition for equipment, supplies and personnel during certain times of the year, which could lead to shortages and increase costs or delay the Company's operations.

ENVIRONMENTAL REGULATIONS

General

The exploration, development and production of oil and natural gas are subject to stringent federal, state, tribal, regional and local laws and regulations governing worker safety and health, the discharge of materials into the environment and environmental protection. Numerous governmental entities, including the U.S. Environmental Protection Agency ("EPA") and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, which may cause the Company to incur significant capital and operating expenditures or costly actions to achieve and maintain compliance. These laws and regulations may, among other things, require permits to conduct drilling, water withdrawal and other regulated activities; govern the types, quantities and concentrations of substances that may be disposed or released into the environment and the manner of any such disposal or release; limit or prohibit construction or drilling activities or require formal mitigation measures in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions arising from the Company's operations or attributable to former operations; impose safety and health restrictions designed to protect employees from exposure to hazardous or dangerous substances; and impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the occurrence of delays or restrictions in permitting or performance of projects and the issuance of orders enjoining operations in affected areas.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus any changes or enhanced enforcement of these laws and regulations that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management or completion activities or waste handling, storage, transport, remediation, or disposal emission or discharge requirements could have a material adverse effect on the Company. Moreover, accidental releases, including spills, may occur in the course of the Company's operations, and there can be no assurance that the Company will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property and natural resources or personal injury. The Company may be unable to pass on such increased compliance costs to our customers.

The following is a summary of the more significant existing environmental and occupational safety and health laws and regulations, as amended from time to time, applicable to the oil and natural gas industry and for which compliance may have a material adverse impact on the Company.

Hazardous Substances and Wastes

The Company currently owns, leases, or operates, and in the past has owned, leased, or operated, properties that have been used to explore for and produce oil and natural gas. The Company believes it has utilized operating and disposal practices that were standard in the industry at the applicable time, but hydrocarbons and wastes may have been disposed or released on or under the properties owned, leased, or operated by the Company or on or under other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes were not under the Company's control. These properties and wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), the federal Resource Conservation and Recovery Act, ("RCRA") and analogous state laws. Under these laws, the Company could be required to remove or remediate previously disposed wastes, to investigate and clean up contaminated property and to perform remedial operations to prevent future contamination or to pay some or all of the costs of any such action.

CERCLA, also known as the Superfund law, and comparable state laws may impose strict joint and several liability without regard to fault or legality of conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release of a hazardous substance occurred as well as entities that disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, these "responsible persons" may be liable for the costs of cleaning up sites where the hazardous substances have been released, into the environment, for damages to natural resources resulting from the release and for the costs of certain environmental and health studies. Additionally, landowners and other third parties may file claims for personal injury and natural resource and property damage allegedly caused by the release of hazardous substances into the environment. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment from a hazardous substance release and to pursue steps to recover costs incurred for those actions from responsible parties. Certain products used by the Company in the course of its exploration, development and production operations may be regulated as CERCLA hazardous substances. To date, no Company-owned or operated site has been designated as a Superfund site, and the Company has not been identified as a responsible party for any Superfund site.

The Company also generates wastes that are subject to the requirements of RCRA and comparable state statutes. RCRA imposes strict "cradle-to-grave" requirements on the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Drilling fluids, produced waters and other wastes associated with the exploration, production and/or development of crude oil and natural gas are currently excluded from regulation as hazardous wastes under RCRA and, instead, are regulated under RCRA's less stringent non-hazardous waste requirements. However, it is possible that these wastes could be classified as hazardous wastes in the future. For example, in August 2015, several non-governmental organizations filed notice of intent to sue the EPA under RCRA for, among other things, the agency's alleged failure to reconsider whether such exclusion should continue to apply. Any change in the exclusion for such wastes could potentially result in an increase in costs to manage and dispose of wastes. In the course of the Company's operations, it generates petroleum hydrocarbon wastes and ordinary industrial wastes that are subject to regulation under the RCRA. The Company believes it is in substantial compliance with all regulations regarding the handling and disposal of oil and natural gas wastes from its operations.

Air Emissions

The federal Clean Air Act, as amended, and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various permitting, monitoring and reporting requirements. These laws and regulations may require the Company to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permit requirements or utilize specific equipment or technologies to control emissions. The need to acquire such permits has the potential to delay or limit the development of oil and natural gas projects. Over the next several years, the Company may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in October 2015, the EPA issued a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. The EPA is required to make attainment and non-attainment designations for specific geographic locations under the revised standards by October 1, 2017. With the EPA lowering the ground-level ozone standard, states may be required to implement more stringent regulations, which could apply to the Company's operations and result in the need to install new emissions controls, longer permitting timelines and significant increases in the Company's capital or operating expenditures. Additionally, violations of lease conditions or regulations related to air emissions can result in civil and criminal penalties, as well as potential court injunctions curtailing operations and canceling leases. Such enforcement liabilities can result from either governmental or citizen prosecution.

Water Discharges

The Federal Clean Water Pollution Control Act, also known as the Clean Water Act (the “CWA”), and analogous state laws and implementing regulations, impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States as well as state waters. Pursuant to these laws and regulations, the discharge of pollutants into regulated waters is prohibited unless it is permitted by the EPA or an analogous state agency. The Company does not presently discharge pollutants associated with the exploration, development and production of oil and natural gas into federal or state waters. The CWA including analogous state laws and regulations also impose restrictions and controls regarding the discharge of sediment via storm water run-off to waters of the United States and state waters from a wide variety of construction activities. Such activities are generally prohibited from discharging sediment unless it is permitted by the EPA or an analogous state agency. However, pursuant to the Federal Energy Policy Act of 2005, storm water discharges related to oil and gas exploration, development and production and meeting certain conditions are exempt from the permitting provisions of the CWA. The Company employs certain controls with respect to construction activities to address the discharge of sediment into nearby water bodies. The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. The EPA issued a final rule in May 2015 that attempts to clarify the federal jurisdictional reach over waters of the United States but this rule has been stayed nationwide by the U.S. Sixth Circuit Court of Appeals as that appellate court and numerous district courts consider lawsuits opposing implementation of the rule. To the extent the rule expands the scope of the CWA’s jurisdiction, the Company could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

Finally, the Oil Pollution Act of 1990 (“OPA”), which amends the CWA, establishes standards for prevention, containment and cleanup of oil spills into waters of the United States. The OPA requires measures to be taken to prevent the accidental discharge of oil into waters of the United States from onshore production facilities. Measures under the OPA and/or CWA include inspection and maintenance programs to minimize spills from oil storage and conveyance systems: the use of secondary containment systems to prevent spills from reaching nearby water bodies; and the development and implementation of spill prevention, control and countermeasure (“SPCC”) plans to prevent and respond to oil spills. The Company has developed and implemented SPCC plans for properties as required under the CWA.

Subsurface Injections

Underground injection operations performed by the Company are subject to the Safe Drinking Water Act (“SDWA”), as well as analogous state laws and regulations. Under the SDWA, the EPA established the Underground Injection Control (“UIC”) program, which established the minimum program requirements for state and local programs regulating underground injection activities. The UIC program includes requirements for permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. State regulations require a permit from the applicable regulatory agencies to operate underground injection wells. Although the Company monitors the injection process of its wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of the Company’s UIC permit, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third-parties claiming damages for alternative water supplies, property damages and personal injuries. Additionally, some states have considered laws mandating the recycling of flowback and produced water. If such laws are adopted in areas where the Company conducts operations, the Company’s operating costs may increase significantly.

Furthermore, in response to recent seismic events near underground disposal wells used for the disposal by injection of produced water resulting from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have restricted, suspended or shut down the use of such disposal wells. For example, in Oklahoma, the Oklahoma Corporation Commission ("OCC") has implemented a variety of measures including adopting the National Academy of Science's "traffic light system," pursuant to which the agency reviews new disposal well applications for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted. The OCC also evaluates existing wells to assess their continued operation, or operation with restrictions, based on location relative to such faults, seismicity and other factors, with certain of such existing wells required to make frequent, or even daily, volume and pressure reports. In addition, the OCC has rules requiring operators of certain saltwater disposal wells in the state to, among other things, conduct mechanical integrity testing or make certain demonstrations of such wells' depth that, depending on the depth, could require the plugging back of such wells and/or the reduction of volumes disposed in such wells. As a result of these measures, the OCC from time to time has developed and implemented plans calling for wells within areas of interest where seismic incidents have occurred to restrict or suspend disposal well operations in an attempt to mitigate the occurrence of such incidents. For example, only recently, in January 2016, the OCC ordered five Arbuckle disposal wells within 10 miles of the center of earthquake activity in the Edmond area of Oklahoma to reduce disposal volumes, with wells within 3.5 miles of the activity ordered to reduce disposal volumes by 50 percent while the other wells within 10 miles of the activity were ordered to reduce their disposal volume by 25 percent. In addition, in January 2016, the Governor of Oklahoma announced a grant of $1.38 million in emergency funds to support earthquake research, which research is to be directed by the OCC and the Oklahoma Geological Survey. Further, on February 16, 2016, the OCC issued its largest volume reduction plan to date, covering approximately 5,281 square miles and 245 disposal wells injecting wastewater into the Arbuckle formation. In the plan, the OCC identified 76 SandRidge operated disposals wells, prescribed a four stage volume reduction schedule and set April 30, 2016 as the final date for compliance with the tiered volume reduction plan.

Additionally, the Governor of Kansas has established a task force composed of various administrative agencies to study and develop an action plan for addressing seismic activity in the state. The task force issued a recommended Seismic Action Plan calling for enhanced seismic monitoring and the development of a seismic response plan, and in November 2014, the Governor of Kansas announced a plan to enhance seismic monitoring in the state. In March 2015, the Kansas Corporation Commission issued its Order Reducing Saltwater Injection Rates. The Order identified five areas of heightened seismic concern in Harper and Sumner Counties and created a timeframe over which the maximum of 8,000 barrels of saltwater injection daily into each well. SandRidge and other operators of injection wells, and any injection well drilled deeper than the Arbuckle Formation was required to be plugged back in a manner approved by the Kansas Corporation Commission. On September 14, 2015, the Kansas Corporation Commission extended the Order Reducing Saltwater Injection Rates until March 13, 2016. Most recently, in February 2016, the Kansas Corporation Commission staff recommended an expansion of the areas of heightened seismic concern, which would include an additional schedule of volume reductions for Arbuckle disposal wells not previously identified in the Order released in March 2015.

Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of saltwater into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where salt water disposal activities occur or are proposed to be performed. The adoption of any new laws, regulations, or directives that restrict the Company’s ability to dispose of saltwater generated by production and development activities , whether by plugging back the depths of disposal wells, reducing the volume of salt water disposed in such wells, restricting disposal well locations or otherwise, or by requiring SandRidge to shut down disposal wells, could significantly increase SandRidge’s costs to manage and dispose of this saltwater, which could negatively affect the economic lives of the affected properties.

Climate Change

The EPA has published its findings that emissions of $CO_2$, methane and certain other greenhouse gases (“GHGs”) present an endangerment 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 changes. Based on its findings, the EPA has adopted and implemented regulations under existing provisions of the Clean Air Act that, among other things, establish Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emission. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that typically are established by the states. This rule could adversely affect the Company’s operations and restrict or delay its ability to obtain air permits for new or modified facilities that exceed GHG emission thresholds. In addition, the EPA has adopted rules requiring the reporting of GHG emissions from oil and natural gas production and processing facilities in the United States on an annual basis. The Company is monitoring and reporting on GHG emissions from certain of its operations upon affected properties.

However, the adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG gases from, the Company's equipment and operations could require it to incur additional costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas it produces. Finally, to the extent 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, floods and other climatic events, such events could have a material adverse effect on the Company and potentially subject the Company to further regulation.

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. As a result, 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 to acquire and surrender emission allowances in return for emitting those GHGs. Any future federal laws or implemented regulations that may be adopted to address GHG emissions could require the Company to incur increased operating costs, adversely affect demand for the oil and natural gas that the Company produces and have a material adverse effect on the Company’s business, financial condition and results of operations. For example, in August 2015, the EPA announced proposed rules, expected to be finalized in 2016, that would establish new controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production activities, as part of an overall effort to reduce methane emissions by up to 45 percent in 2025. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measure each country will use to achieve its GHG emissions targets. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the international agreement agreed to in Paris. Any such legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for the Company’s oil, natural gas and NGL production, and thus possibly have a material adverse effect on the Company’s revenues.

Endangered or Threatened Species

The Endangered Species Act (the “ESA”) restricts activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act. While the Company believes its operations are in substantial compliance with the ESA, exploration and production operations in areas where threatened or endangered species or their habitat are known to exist may require the Company to incur increased costs to implement mitigation or protective measures and also may delay, restrict or preclude drilling activities in those areas or during certain seasons, such as breeding and nesting seasons. If endangered species are located in areas where the Company wishes to conduct seismic surveys, development activities or abandonment operations, the work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in 2011, the U.S. Fish and Wildlife Service (the “FWS”) is required to consider listing numerous species as endangered under the ESA by the end of the agency’s 2017 fiscal year.

For example, in March 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Oklahoma, Kansas and Texas, where the Company operates, as a threatened species under the ESA. However, on September 1, 2015, the U.S. District Court for the Western District of Texas vacated the FWS’ rule listing the lesser prairie chicken in its entirety, concluding that the decision to list the species was arbitrary and capricious. As a result of the 2014 listing of the lesser prairie chicken, the Company had entered into a range-wide conservation planning agreement, pursuant to which the Company agreed to take measures to protect the lesser prairie chicken’s habitat and to pay a mitigation fee if the Company’s actions harmed the lesser prairie chicken’s habitat. Notwithstanding the 2015 decision by the Western District of Texas Court, the Company has continued its participation in the conservation planning agreement. Whether the lesser prairie chicken or other species will be listed in the future under the ESA is currently unknown but the designation of the lesser prairie chicken or any other previously unprotected species as threatened or endangered in areas where the Company operates could cause the Company 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 impact on its ability to develop and produce reserves.

The Company is an active participant on various agency and industry committees that are developing or addressing various EPA and other federal and state agency programs to minimize potential impacts to business activity relating to the protection of any endangered or threatened species.

Employee Health and Safety

The Company's operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA Hazardous Communication Standard requires that information be maintained concerning hazardous materials used or produced in the Company's operations and that this information be provided to employees. Pursuant to the Federal Emergency Planning and Community Right-to-Know Act, also known as Title III of the Federal Superfund Amendment and Reauthorization Act, facilities that store threshold amounts of chemicals that are subject to OSHA's Hazardous Communication Standard above certain threshold quantities must submit information regarding those chemicals by March 1 of each year to state and local authorities in order to facilitate emergency planning and response. That information is generally available to the public. The Company believes that it is in substantial compliance with all applicable laws and regulations relating to worker health and safety.

State Regulation

The states in which the Company operates, along with some municipalities and Native American tribal areas, regulate some or all of the following activities: the drilling for, and the production and gathering of, oil and natural gas, including requirements relating to drilling permits, the location, spacing and density of wells, unitization and pooling of interests, the method of drilling, casing and equipping of wells, the protection of fresh water sources, the orderly development of common sources of supply of oil and natural gas, the operation of wells, allowable rates of production, the use of fresh water in oil and natural gas operations, saltwater injection and disposal operations, the plugging and abandonment of wells and the restoration of surface properties, the prevention of waste of oil and natural gas resources, the protection of the correlative rights of oil and natural gas owners and, where necessary to avoid unfair, unjust or discriminatory service, the fees, terms and conditions for the gathering of natural gas. These regulations may affect the number and location of the Company’s wells and the amounts of oil and natural gas that may be produced from the Company’s wells, and increase the costs of the Company’s operations.

Hydraulic Fracturing

Oil and natural gas may be recovered from certain of the Company’s oil and natural gas properties through the use of hydraulic fracturing, combined with sophisticated drilling. Hydraulic fracturing, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and gas commissions. However, several federal agencies have asserted federal regulatory authority over certain aspects of the hydraulic fracturing process. For example, the EPA issued the Clean Air Act final regulations in 2012 and proposed additional Clean Air Act regulations in August 2015 governing performance standards for the oil and natural gas industry; proposed in April 2015 effluent limitations guidelines that waste water from shale natural gas extraction operations must meet before discharging to a treatment plant; and issued in 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, the U.S. Department of the Interior, Bureau of Land Management (“BLM) published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands but, in September 2015, the U.S. District Court of Wyoming issued a preliminary injunction barring implementation of this rule, which order the BLM could appeal and is being separately appealed by certain environmental groups.

The BLM also proposed new rules in January 2016 which seek to limit methane emissions from new and existing oil and gas operations on federal lands. The proposal would limit venting and flaring of gas, impose leak detection and repair requirements on wellsite equipment and compressors, and also require the installation of new controls on pneumatic pumps, and other activities at the wellsite such as downhole well maintenance and liquids unloading and drilling workovers and completions to reduce leaks of methane.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Oklahoma, have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure, or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. Local government may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at either the state or federal level, the Company’s fracturing activities could become subject to additional permit requirements, reporting requirements or operational restrictions and also to associated permitting delays and potential increases in costs. These delays or additional costs could adversely affect the determination of whether a well is commercially viable. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce in commercial quantities.

In addition to asserting regulatory authority, certain government reviews are underway that focus on environmental issues associated with hydraulic fracturing practices. For example, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Also, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources in June 2015, which report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. However, in January 2016, the EPA’s Science Advisory Board provided its comments on the draft study, indicating its concern that EPA's conclusion of no widespread, systemic impacts on drinking water sources arising from fracturing activities did not reflect the uncertainties and data limitations associated with such impacts, as described in the body of the draft report. The final version of this EPA report remains pending and is expected to be completed in 2016. Such EPA final report, when issued, as well as any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing.

The Company diligently reviews best practices and industry standards, serves on industry association committees and complies with all regulatory requirements in the protection of potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across the potable water sources and cementing these pipes from setting depth to surface, continuously monitoring the hydraulic fracturing process in real time and disposing of all non-commercially produced fluids in certified disposal wells at depths below the potable water sources. There have not been any incidents, citations or suits related to the Company's hydraulic fracturing activities involving environmental concerns.

OTHER REGULATION OF THE OIL AND NATURAL GAS INDUSTRY

The oil and natural gas industry is extensively regulated by numerous federal, state, local, and regional authorities, as well as Native American tribes. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations affecting the oil and natural gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and natural gas industry increases the Company's cost of doing business and, consequently, affects its profitability, these burdens generally do not affect the Company any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission ("FERC"). Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

In July 2014, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") released the details of a comprehensive rulemaking proposal to improve the safe transportation of large quantities of flammable materials by rail, particularly crude oil and ethanol. The Federal Railroad Administration and PHMSA jointly published the final rule on May 1, 2015, and it became effective July 7, 2015. The final rule (i) contains a new enhanced tank car standard and a risk-based retrofitting schedule for older tank cars carrying crude oil and ethanol; (ii) requires a new braking standard for certain trains; (iii) designates new operational protocols for trains transporting large volumes of flammable liquids, such as routing requirements, speed restrictions, and information for local government agencies; and (iv) provides new sampling and testing requirements to improve classification of energy products placed into transport.

Sales of oil, natural gas and NGLs are not currently regulated and are made at market prices. Although oil, natural gas and NGL prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. The Company cannot predict whether new legislation to regulate oil, natural gas and NGLs might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the Company's operations.

Drilling and Production

The Company’s operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribal areas where the Company operates also regulate one or more of the following activities:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities;
- the rates of production, or “allowables”;

- the use of surface or subsurface waters;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company's interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas the Company can produce from its wells or limit the number of wells or the locations at which the Company can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas, and natural gas liquids within its jurisdiction.

The Oil Conservation Division of the New Mexico Energy, Minerals and Natural Resources Department requires the posting of financial assurance for owners and operators on privately owned or state land within New Mexico in order to provide for abandonment restoration and remediation of wells. The Railroad Commission of Texas imposes financial assurance requirements on operators. The United States Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration.

Natural Gas Sales and Transportation

Historically, federal legislation and regulatory controls have affected the price of the natural gas the Company produces and the manner in which the Company markets its production. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of the Company's sales of its own production. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which the Company may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that the Company produces, as well as the revenues it receives for sales of its natural gas and release of its natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, the Company cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can the Company determine what effect, if any, future regulatory changes might have on the Company's natural gas related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in-state waters. Although its policy is still in flux, in the past FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase the Company’s cost of transporting gas to point-of-sale locations.

Subsurface Injections

Our underground injection operations are subject to the SDWA, as well as analogous state laws and regulations. Under the SDWA, the EPA established the Underground Injection Control, or UIC, program, which established the minimum program requirements for state and local programs regulating underground injection activities. The UIC program includes requirements for permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. State regulations require the Company to obtain a permit from the applicable regulatory agencies to operate the Company’s underground injection wells. Although the Company monitors the injection process of its wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of the Company’s UIC permit, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third-parties claiming damages for alternative water supplies, property damages and personal injuries. Additionally, some states, including Texas, have considered laws mandating the recycling of flowback and produced water. If such laws are passed, the Company’s operating costs may increase significantly.

## EMPLOYEES

As of December 31, 2015, the Company had 1,165 full-time employees, including 173 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of the Company’s 1,165 employees, 552 were located at the Company’s headquarters in Oklahoma City, Oklahoma at December 31, 2015, and the remaining employees worked in the Company’s various field offices and drilling sites. The Company completed a reduction in force during the first quarter of 2016, and as of March 2, 2016, had 864 full-time employees, including 153 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Approximately 369 of the total full-time employees at March 2, 2016, were located at the Company’s headquarters in Oklahoma City, Oklahoma.

## GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of certain oil and natural gas industry terms used in this report.

2-D seismic or 3-D seismic. Geophysical data that depict the subsurface strata in two dimensions or three dimensions, respectively. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic.

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

Bcf. Billion cubic feet of natural gas.

Bench. A geological horizon; a thin, distinctive stratum useful for stratigraphic correlation.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil. Although an equivalent barrel of condensate or natural gas may be equivalent to a barrel of oil on an energy basis, it is not equivalent on a value basis as there may be a large difference in value between an equivalent barrel and a barrel of oil. For example, based on the commodity prices used to prepare the estimate of the Company’s reserves at year-end 2015 of $46.79/Bbl for oil and $2.59/Mcf for natural gas, the ratio of economic value of oil to gas was approximately 18 to 1, even though the ratio for determining energy equivalency is 6 to 1.

Boe/d. Boe per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

$CO_2$. Carbon dioxide.

Developed acreage. The number of acres that are assignable to productive wells.

Developed oil, natural gas and NGL reserves. Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (ii) drill and equip development wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.
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 well. An exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.
Environmental Assessment ("EA"). A study to determine whether an action significantly affects the environment, which federal or state agencies may be required by the National Environmental Policy Act or similar state statutes to undertake prior to the commencement of activities that would constitute federal or state actions, such as permitting oil and natural gas exploration and production activities.
Environmental Impact Statement. A more detailed study of the environmental effects of an undertaking and its alternatives than an EA, which may be required by the National Environmental Policy Act or similar state statutes, either after the EA has been prepared and determined that the environmental consequences of a proposed federal undertaking, such as permitting oil and natural gas exploration and production activities, may be significant, or without the initial preparation of an EA if a federal or state agency anticipates that a proposed undertaking may significantly impact the environment.
Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to produce oil or natural gas in another reservoir.
Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geological barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.
Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.
MBbls. Thousand barrels of oil or other liquid hydrocarbons.
MBoe. Thousand barrels of oil equivalent.
Mcf. Thousand cubic feet of natural gas.
MMBbls. Million barrels of oil or other liquid hydrocarbons.
MMBoe. Million barrels of oil equivalent.
MMBtu. Million British Thermal Units.
MMcf. Million cubic feet of natural gas.
MMcf/d. MMcf per day.
Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.
NGL. Natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.
NYMEX. The New York Mercantile Exchange.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
Present value of future net revenues ("PV-10"). The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation and without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization. PV-10 is calculated using an annual discount rate of 10%.
Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities, that become part of the cost of oil and gas produced.
Productive well. A well that is found to be capable of producing oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.
Prospect. A specific geographic area that, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved developed reserves. Reserves that are both proved and developed.
Proved oil, natural gas and NGL reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as:
Those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.
Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.
Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.
Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
Proved undeveloped reserves. Reserves that are both proved and undeveloped.

Pulling units. Pulling units are used in connection with completions and workover operations.
PV-10. See “Present value of future net revenues” above.

Rental tools. A variety of rental tools and equipment, ranging from trash trailers to blowout preventers to sand separators, for use in the oilfield.
Reserves. Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.
Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).
Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
Roustabout services. The provision of manpower to assist in conducting oilfield operations.
Standardized measure or standardized measure of discounted future net cash flows. The present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes on future net revenues.
Trucking. The provision of trucks to move the Company’s drilling rigs from one well location to another and to deliver water and equipment to the field.
Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.
Undeveloped oil, natural gas and NGL reserves. Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Item 1A. Risk Factors

The Company has engaged advisors to assist with a private restructuring or reorganization under Title 11 of the U.S. Bankruptcy Code in the foreseeable future, which raises substantial doubt about its ability to continue as a going concern.

As a result of the impacts to the Company's financial position resulting from declining industry conditions and in consideration of the substantial amount of long-term debt outstanding, the Company has engaged advisors to assist with the evaluation of strategic alternatives, which may include, but not be limited to, seeking a restructuring, amendment or refinancing of existing debt through a private restructuring or reorganization under Chapter 11 of the Bankruptcy Code. However, there can be no assurances that the Company will be able to successfully restructure its indebtedness, improve its financial position or complete any strategic transactions. As a result of these uncertainties and the likelihood of a restructuring or reorganization, management has concluded that there is substantial doubt regarding the Company's ability to continue as a going concern as it is currently structured.

As a result, the report of the Company's independent registered public accounting firm that accompanies these consolidated financial statements for the year ended December 31, 2015 contains an explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern, which under the terms of the Company's senior secured revolving credit facility ("senior credit facility") may result in an event of default. If the Company does not obtain a waiver of this requirement or otherwise cure this event within 30 calendar days of the issuance of these financial statements, the lenders under the senior credit facility will be able to accelerate maturity of the debt. Any acceleration of the obligations under the senior credit facility would result in a cross-default and potential acceleration of the maturity of the Company's other outstanding long-term debt. These defaults create additional uncertainty associated with the Company's ability to repay its outstanding long-term debt obligations as they become due and further reinforces the substantial doubt over the Company's ability to continue as a going concern.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect the Company's business, financial condition or results of operations.
Drilling for oil and natural gas can be unprofitable if dry wells are drilled and if productive wells do not produce sufficient revenues to return a profit. Furthermore, even if sufficient amounts of oil or natural gas exist, the Company may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. Decisions to develop properties depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The estimated cost of drilling, completing and operating wells is uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. In addition, the Company's drilling and producing operations may be curtailed, delayed or canceled as a result of various factors, including the following:

- reductions in oil, natural gas and NGL prices;
- delays imposed by or resulting from compliance with regulatory requirements including permitting;
- unusual or unexpected geological formations and miscalculations;
- shortages of or delays in obtaining equipment and qualified personnel;
- shortages of or delays in obtaining water for hydraulic fracturing operations;
- equipment malfunctions, failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- lack of adequate electrical infrastructure and water disposal capacity;
- unexpected operational events and drilling conditions;
- pipe or cement failures and casing collapses;

- pressures, fires, blowouts and explosions;
- lost or damaged drilling and service tools;
- loss of drilling fluid circulation;
- uncontrollable flows of oil, natural gas, brine, water or drilling fluids;

- natural disasters;
- environmental hazards, such as oil spills and natural gas leaks, pipeline or tank ruptures, encountering naturally occurring radioactive materials and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- high costs, shortages or delivery delays of equipment, labor or other services, or water used in hydraulic fracturing;
- compliance with environmental and other governmental requirements;
- adverse weather conditions such as extreme cold, fires caused by extreme heat or lack of rain, and severe storms, tornadoes or hurricanes;
- oil and natural gas property title problems; and
- market limitations for oil, natural gas and NGLs.

Certain of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, environmental contamination or loss of wells and regulatory fines or penalties.

Oil, natural gas and NGL prices can fluctuate widely due to a number of factors that are beyond the Company's control. Continued depressed or further declining oil, natural gas or NGL prices could significantly affect the Company's financial condition and results of operations.

The Company's revenues, profitability and cash flow are highly dependent upon the prices it realizes from the sale of oil, natural gas and NGLs. The markets for these commodities are very volatile and have experienced significant decline during the latter half of 2014, throughout 2015, and into 2016. Oil, natural gas and NGL prices can move quickly and fluctuate widely in response to a variety of factors that are beyond the Company's control. These factors include, among others:

- changes in regional, domestic and foreign supply of, and demand for, oil, natural gas and NGLs, as well as perceptions of supply of, and demand for, oil, natural gas and NGLs generally;
- the price and quantity of foreign imports;
- the ability of other companies to complete and commission liquefied natural gas export facilities in the U.S.;
- U.S. and worldwide political and economic conditions;
- weather conditions and seasonal trends;
- anticipated future prices of oil, natural gas and NGLs, alternative fuels and other commodities;
- technological advances affecting energy consumption and energy supply;
- the proximity, capacity, cost and availability of pipeline infrastructure, treating, transportation and refining capacity;
- natural disasters and other extraordinary events;
- domestic and foreign governmental regulations and taxation;
- energy conservation and environmental measures; and
- the price and availability of alternative fuels.

For oil, from January 2011 through December 2015, the highest month end NYMEX settled price was $113.93 per Bbl and the lowest was $37.04 per Bbl. For natural gas, from January 2011 through December 2015, the highest month end NYMEX settled price was $5.56 per MMBtu and the lowest was $2.03 per MMBtu. In addition, the market price of oil and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil and natural gas for heating purposes during the winter season.

Oil prices dropped sharply during the latter half of 2014 and have continued to decline throughout 2015 and into 2016, and settled as low as $26.21 per Bbl in February 2016. Continued low oil, natural gas or NGL prices will decrease the Company's cash flows and revenues, and also may ultimately reduce the amount of oil, natural gas and NGLs that it can produce economically, causing the Company to make substantial downward adjustments to its estimated proved reserves and having a material adverse effect on its financial condition and results of operations.

Unless the Company replaces its oil, natural gas and NGL reserves, its reserves and production will decline, which would adversely affect the Company's business, financial condition and results of operations.

The Company's future oil, natural gas and NGL reserves and production, and therefore its cash flow and income, are highly dependent on its success in efficiently developing and exploiting its current reserves and finding or acquiring additional economically recoverable reserves. Declining cash flows from operations, as a result of lower commodity prices, could require the Company to reduce expenditures to develop and acquire additional reserves. Further, the Company may not be able to develop, find or acquire additional reserves to replace its current and future production at acceptable costs, which could adversely affect its business, financial condition and results of operations.

Future price declines may result in reductions of the asset carrying values of the Company's oil and natural gas properties.

The Company utilizes the full cost method of accounting for costs related to its oil and natural gas properties. Under this accounting method, all costs for both productive and nonproductive properties are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, the amount of these costs that can be carried as capitalized assets is subject to a ceiling, which limits such pooled costs to the aggregate of the present value of future net revenues of proved oil, natural gas and NGL reserves attributable to proved properties, discounted at 10%, plus the lower of cost or market value of unevaluated properties. The full cost ceiling is evaluated at the end of each quarter using the most recent 12-month average prices for oil and natural gas, adjusted for the impact of derivatives accounted for as cash flow hedges. The Company incurred a full cost ceiling impairment charge of $4.5 billion for the year ended December 31, 2015, and had cumulative full cost ceiling impairment charges of $8.2 billion and $3.7 billion at December 31, 2015 and 2014, respectively. The Company incurred a full cost ceiling impairment charge of $164.8 million for the year ended December 31, 2014, and had no full cost ceiling impairment during the year ended December 31, 2013. If oil, natural gas and NGL prices fail to recover significantly in the near term, and without other mitigating circumstances, the Company will experience additional losses of future net revenues, including losses attributable to quantities that cannot be economically produced at lower prices, which would likely cause the Company to record additional write-downs of capitalized costs of its oil and natural gas properties and non-cash charges against future earnings. The amount of such future write-downs and non-cash charges could be substantial. Further, the borrowing base under the senior credit facility is calculated by reference to the value of the Company's oil and natural gas reserves, as determined by the lenders under the senior credit facility, and declines in the value of such reserves as a result of sustained low commodity prices resulted in a reduction to the borrowing base in March 2016 and could further reduce the amount available to be borrowed by the Company under its senior credit facility if prices decline further from current levels.

The Company has a substantial amount of indebtedness and other obligations and commitments, which may adversely affect its cash flow and its ability to operate its business.

As of December 31, 2015, the Company's total indebtedness was $3.6 billion and the Company had preferred stock outstanding with an aggregate liquidation preference of $542.0 million. The Company's substantial level of indebtedness and the dividends associated with its outstanding preferred stock increases the possibility that it may be unable to generate cash sufficient to pay, when due, the principal of, interest on or other amounts due in respect of the Company's indebtedness and/or the preferred stock dividends. Declining cash flows from operations, as a result of declines in oil and natural gas prices, may increase the Company's borrowing needs under its senior credit facility to fund working capital. The Company's indebtedness and outstanding preferred stock, combined with its lease and other financial obligations and contractual commitments, could have other important consequences to the Company. For example, it could:

- make the Company more vulnerable to adverse changes in general economic, industry and competitive conditions and adverse changes in government regulation;
- require the Company to dedicate an even greater portion of its cash flow from operations to payments on its indebtedness, thereby reducing the availability of the Company's cash flows to fund working capital, capital expenditures, acquisitions and other general corporate purposes;

- require the Company to finance an increasing portion of its working capital and capital expenditures with cash on hand and borrowing under its senior credit facility;
- limit the Company’s flexibility in planning for, or reacting to, changes in its business and the industry in which it operates;
- place the Company at a disadvantage compared to its competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that the Company’s indebtedness prevents it from pursuing; and
- limit the Company’s ability to borrow additional amounts for working capital, capital expenditures, acquisitions, debt service requirements, execution of its business strategy or other purposes.

Any of the above listed factors could have a material adverse effect on the Company's business, financial condition and results of operations.

The Company's estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of the Company's reserves. The Company's current estimates of reserves could change, potentially in material amounts, in the future.
The process of estimating oil, natural gas and NGL reserves is complex and inherently imprecise, requiring interpretations of available technical data and many assumptions, including assumptions relating to production rates and economic factors such as historic oil and natural gas prices, drilling and operating expenses, capital expenditures, the assumed effect of governmental regulation and availability of funds for development expenditures. Inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of the Company's reserves. See "Business—Business Segments and Primary Operations" in Item 1 of this report for information about the Company's oil, natural gas and NGL reserves.

Actual future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves will vary and could vary significantly from the Company's estimates shown in this report, which in turn could have a negative effect on the value of the Company's assets. In addition, from time to time in the future, the Company will adjust estimates of proved reserves, potentially in material amounts, to reflect production history, results of exploration and development, changes in oil, natural gas and NGL prices and other factors, many of which are beyond the Company's control.

The present value of future net cash flows from the Company's proved reserves calculated in accordance with SEC guidelines are not the same as the current market value of its estimated oil, natural gas and NGL reserves.
The Company bases the estimated discounted future net cash flows from its proved reserves on 12-month average index prices and costs, as is required by SEC rules and regulations. Commodity prices have remained depressed and have at times trended lower. Accordingly, if the Company had prepared its December 31, 2015 reserve reports based on the updated 12-month average index prices (which were $42.77 and $2.40 through March 1, 2016) instead of the 12-month average index prices (which were $46.79 and $2.59), and without regard to additions or other further revisions to reserves other than as a result of such pricing changes, the PV-10 value of its internally estimated proved reserves would have decreased by approximately $229.0 million. Actual future net cash flows from the Company's oil and natural gas properties will be affected by actual prices the Company receives for oil, natural gas and NGLs, as well as other factors such as:
- the accuracy of the Company's reserve estimates;
- the actual cost of development and production expenditures;
- the amount and timing of actual production;
- supply of and demand for oil, natural gas and NGLs; and
- changes in governmental regulation or taxation.

The timing of both the Company's production and its incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the Company uses a 10% discount factor when calculating discounted future net cash flows, which may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and natural gas industry in general.

The Company will not know conclusively prior to drilling whether oil or natural gas will be present in sufficient quantities to be economically producible.
The cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive or may suffer from declining production faster than anticipated. The use of seismic data and other technologies and the

study of producing fields in the same area do not enable the Company to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. During 2015, the Company completed a total of 176 gross wells, none of which were identified as dry wells. If the Company drills additional wells that it identifies as dry wells in its current and future prospects, its drilling success rate may decline and materially harm its business.

Production of oil, natural gas and NGLs could be materially and adversely affected by natural disasters or severe weather.
Production of oil, natural gas and NGLs could be materially and adversely affected by natural disasters or severe weather. Repercussions of natural disasters or severe weather conditions may include:
- evacuation of personnel and curtailment of operations;
- damage to drilling rigs or other facilities, resulting in suspension of operations;
- inability to deliver materials to worksites; and
- damage to, or shutting in of, pipelines and other transportation facilities.

In addition, the Company's hydraulic fracturing operations require significant quantities of water. Regions in which the Company operates have recently experienced drought conditions. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail the Company's operations or otherwise result in delays in operations or increased costs.

The capital markets could be volatile, and such volatility could adversely affect the Company's ability to obtain capital, cause it to incur additional financing expense or affect the value of certain assets.
During and following the recent global financial crisis, financial and capital markets were volatile due to multiple factors, including significant losses in the financial services sector and uncertain and rapidly changing economic conditions both in the U.S. and globally. In some cases, financial markets produced downward pressure on stock prices and credit capacity for certain issuers without regard to those issuers' underlying financial and/or operating strength. Volatility in the capital markets can significantly increase the cost of raising money in the debt and equity capital markets. Future market volatility, generally, and persistent weakness in commodity prices may adversely affect the Company's ability to access capital and credit markets or to obtain funds at low interest rates or on other advantageous terms. These factors may adversely affect the Company's business, results of operations or liquidity.

These factors may also adversely affect the value of certain of the Company's assets and its ability to draw on its senior credit facility. Adverse credit and capital market conditions may require the Company to reduce the carrying value of assets associated with derivative contracts to account for non-performance by, or increased credit risk from, counterparties to those contracts. If financial institutions that have extended credit commitments to the Company are adversely affected by volatile conditions of the U.S. and international capital markets, they may become unable to fund borrowings under their credit commitments to the Company, which could have a material adverse effect on its financial condition and its ability to borrow additional funds, if needed, for working capital, capital expenditures and other corporate purposes.

Properties acquired by the Company may not produce as projected, and the Company may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.
The Company's initial technical reviews of properties it acquires are necessarily limited because an in-depth review of every individual property involved in each acquisition generally is not feasible. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well and environmental problems, such as soil or ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Company may assume certain environmental and other risks and liabilities in connection with acquired properties, and such risks and liabilities could have a material adverse effect on its results of operations and financial condition.

The development of the Company's proved undeveloped reserves may take longer and may require higher levels of capital expenditures than the Company currently anticipates.
As of December 31, 2015, approximately 19.7% of the Company's total reserves were proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than the Company currently anticipates. Therefore, recoveries from these fields may not match current expectations. Delays in the

development of the Company’s reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of the Company’s estimated proved undeveloped reserves and future net revenues estimated for such reserves.

A significant portion of the Company's operations are located in the Mid-Continent region, making it vulnerable to risks associated with operating in a limited number of major geographic areas.
As of December 31, 2015, approximately 79.8% of the Company's proved reserves and approximately 88.5% of its annual production was located in the Mid-Continent. This concentration could disproportionately expose the Company to operational and regulatory risk in these areas. This relative lack of diversification in location of its key operations could expose the Company to adverse developments in these areas or the oil and natural gas markets, including, for example, transportation or treatment capacity constraints, curtailment of production due to weather, electrical outages, treatment plant closures for scheduled maintenance or other factors. These factors could have a significantly greater impact on the Company's financial condition, results of operations and cash flows than if the Company's properties were more diversified.

The Company's development and exploration operations require substantial capital, and the Company may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in the Company's oil, natural gas and NGL reserves.
The oil and natural gas industry is capital intensive. The Company makes substantial capital expenditures in its business and operations for the exploration, development, production and acquisition of oil, natural gas and NGL reserves. Historically, the Company has financed capital expenditures primarily with proceeds from asset sales and from the sale of equity and debt securities and cash generated by operations. In particular, the Company had cash flow from operations of $373.5 million, $621.1 million and $868.6 million, for the years ended December 31, 2015, 2014 and 2013, respectively. However, as a result of sustained depressed commodity prices, the capital markets that the Company has historically accessed are currently constrained to such an extent that debt or equity capital raises are practically unfeasible. If the debt and equity capital markets do not improve, the Company may be unable to implement its drilling and development plans or otherwise carry out its business strategy as expected. The Company's cash flow from operations and access to capital are subject to a number of variables, including:

- the prices at which oil, natural gas and NGLs are sold;
- the Company's proved reserves;
- the level of oil, natural gas and NGLs it is able to produce from existing wells;
- the Company's ability to acquire, locate and produce new reserves; and
- the Company's capital and operating costs.

Oil prices fell sharply in the latter half of 2014 and have continued to decline throughout 2015 and into 2016, and continued low prices will reduce the Company's revenues and cash flow from operations. Reductions in the Company's revenues and cash flow from operations, whether as a result of lower oil, natural gas and NGL prices, lower production, declines in reserves or for any other reason, may limit the Company's ability to obtain the capital necessary to sustain its operations at desired levels. In order to fund capital expenditures, the Company may seek additional financing. However, the Company's senior credit facility contains covenants limiting its ability to incur additional indebtedness, and the Company's lenders may withhold their consent to exceed the limitations in such covenants at their sole discretion. The Company's senior note indentures also contain covenants that may restrict the Company's ability to incur additional indebtedness if it does not satisfy certain financial metrics. The Company significantly lowered its capital expenditures plan for 2015 due, in part, to sustained low commodity prices. If prices remain at low levels and the Company is unable to obtain additional financing, it may be necessary for the Company to further reduce or even suspend its capital expenditures.

Disruptions in the global financial and capital markets also could adversely affect the Company's ability to obtain debt or equity financing on favorable terms, or at all. The failure to obtain additional financing could result in a curtailment of the Company's operations relating to exploration and development of its prospects, which in turn could lead to a possible loss of properties and a decline in the Company's oil, natural gas and NGL reserves.

The agreements governing the Company’s existing indebtedness have restrictions, financial covenants and borrowing base redeterminations, which could adversely affect its operations.

The Company’s senior credit facility and the indentures governing its senior notes restrict the Company’s ability to, among other things, obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. The senior credit facility also requires the Company to comply with certain financial covenants and ratios. See additional discussion of the senior credit agreement amendment under “Cash Flows-Senior Credit Facility.” Persistent depressed oil or natural gas prices or further decline in such prices, without other mitigating circumstances, could prevent the Company from complying with the financial covenants under its amended senior credit facility. The Company’s failure to comply with any of the restrictions and covenants under the senior credit facility, senior notes or other debt financings could result in a default under those instruments, which, if left uncured, could lead to an event of default. Such an event of default could, among other things, result in all of its existing indebtedness to be immediately due and payable. Additionally, an event of default under one of the Company's financing instruments could trigger cross-default provisions under the Company's other financing instruments. The application of the remedies under the financing instruments could have a material adverse effect on the Company's financial position.

The Company's senior credit facility limits the amounts it can borrow to a borrowing base amount. The borrowing base is subject to review semi-annually; however, the lenders reserve the right to have one additional redetermination of the borrowing base per calendar year. Unscheduled redeterminations may be made at the Company's request, but are limited to two requests per year. Borrowing base determinations are based upon proved developed producing reserves, proved developed non-producing reserves and proved undeveloped reserves. Outstanding borrowings exceeding the borrowing base must be repaid promptly, or the Company must pledge other oil and natural gas properties as additional collateral. The Company may not have the financial resources in the future to make any mandatory principal prepayments under the senior credit facility, which are required, for example, when the committed line of credit is exceeded, proceeds of asset sales in new oil and natural gas properties are not reinvested, or indebtedness that is not permitted by the terms of the senior credit facility is incurred. If the indebtedness under the Company's senior credit facility and senior notes were to be accelerated, the Company's assets may not be sufficient to repay such indebtedness in full.

On March 21, 2016, the Company notified the administrative agent that the Company would submit for the administrative agent's consideration proposed additional oil and gas properties to serve as collateral under the senior credit facility sufficient to support a borrowing base of $500.0 million. Additionally, the Company notified the administrative agent that it believed the currently pledged assets are sufficient to support a borrowing base of $500.0 million and reserved the right to exercise all other options available to remedy the borrowing base deficiency, if any. The Company has until April 20, 2016 to submit such additional properties.

The Company's derivative activities could result in financial losses and reduce earnings.
To achieve a more predictable cash flow and to reduce its exposure to adverse fluctuations in the prices of oil and natural gas, the Company currently has entered, and may in the future enter, into derivative contracts for a portion of its future oil and natural gas production, including fixed price swaps, collars and basis swaps. The Company has not designated and does not plan to designate any of its derivative contracts as hedges for accounting purposes and, as a result, records all derivative contracts on its balance sheet at fair value with changes in the fair value recognized in current period earnings. Accordingly, the Company's earnings may fluctuate significantly as a result of changes in the fair value of its derivative contracts. Derivative contracts also expose the Company to the risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counterparty to the derivative contract defaults on its contract obligations; or
- the actual differential between the underlying price in the derivative contract and actual prices received is materially different from that expected.

In addition, these types of derivative contracts can limit the benefit the Company would receive from increases in the prices for oil and natural gas.

The Company's services revenues depend on the needs of other companies in the oil and natural gas industry.
Companies to which the Company provides oilfield services are affected by the oil and natural gas industry risks mentioned above. Market prices of oil, natural gas and NGLs, limited access to capital and reductions in capital expenditures could result in oil and natural gas companies canceling or curtailing their drilling programs, which could reduce the demand for the Company's oilfield services. Any prolonged reduction in the overall level of exploration and development activities, whether resulting from changes in oil, natural gas and NGL prices or otherwise, could impact the Company's oilfield services segment by negatively affecting revenues, cash flow and profitability;

Oil and natural gas wells are subject to operational hazards that can cause substantial losses for which the Company may not be adequately insured.

There are a variety of operating risks inherent in oil, natural gas and NGL production and associated activities, such as fires, leaks, explosions, mechanical problems, major equipment failures, blowouts, uncontrollable flow of oil, natural gas and NGLs, water or drilling fluids, casing collapses, abnormally pressurized formations and natural disasters. The occurrence of any of these or similar accidents that temporarily or permanently halt the production and sale of oil, natural gas and NGLs at any of the Company's properties could have a material adverse impact on its business activities, financial condition and results of operations.

Additionally, if any of such risks or similar accidents occur, the Company could incur substantial losses as a result of injury or loss of life, severe damage or destruction of property, natural resources and equipment, regulatory investigation and penalties and environmental damage and clean-up responsibility. If the Company experiences any of these problems, its ability to conduct operations could be adversely affected. While the Company maintains insurance coverage that it deems appropriate for these risks, its operations may result in liabilities exceeding such insurance coverage or liabilities not covered by insurance.

Shortages or increases in costs of equipment, services and qualified personnel could adversely affect the Company's ability to execute its exploration and development plans on a timely basis and within its budget.
The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Additionally, higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could significantly affect the Company's ability to execute its exploration and development plans as projected.

Market conditions or operational impediments may hinder the Company's access to oil, natural gas and NGL markets or delay production of oil, natural gas and NGLs.
Market conditions or a lack of satisfactory oil and natural gas transportation arrangements may hinder the Company's access to oil, natural gas and NGL markets or delay production of oil, natural gas and NGLs. The availability of a ready market for the Company's oil, natural gas and NGL production depends on a number of factors, including the demand for and supply of oil, natural gas and NGLs and the proximity of reserves to pipelines and terminal facilities. The Company's ability to market its production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and treating facilities for oil, natural gas and NGLs as well as gathering systems, treating facilities and disposal wells for water produced alongside the hydrocarbons. The Company's failure to obtain such services on acceptable terms in the future or to expand its midstream assets could have a material adverse effect on its business. The Company may be required to shut in wells for a lack of a market or because access to natural gas pipelines, gathering system capacity, treating facilities or disposal wells may be limited or unavailable. The Company would be unable to realize revenue from any shut-in wells until production arrangements were made to deliver the production to market.

Competition in the oil and natural gas industry is intense, which may adversely affect the Company's ability to succeed.
The oil and natural gas industry is intensely competitive, and the Company competes with many companies that have greater financial and other resources than it does. Many of these companies not only explore for and produce oil and natural gas, but also conduct refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than the Company's financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. The Company's larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than it can, which would adversely affect its competitive position.

The Company's use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the results of the Company's drilling operations.
A significant aspect of the Company's exploration and development plan involves seismic data. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether

hydrocarbons are present in those structures. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than the Company's professionals. The Company's drilling activities may not be geologically successful or economical, and its overall drilling success rate or its drilling success rate for activities in a particular area may not improve as a result of using 2-D and 3-D seismic data.

The use of 2-D and 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and the Company could incur losses due to such expenditures. In addition, the Company may often gather 2-D and 3-D seismic data over large areas. The Company's interpretation of seismic data delineates for it those portions of an area that it believes are desirable for drilling. Therefore, the Company may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, the Company may identify hydrocarbon indicators before seeking option or lease rights in the location. If the Company is not able to lease those locations on acceptable terms, it will have made substantial expenditures to acquire and analyze 2-D and 3-D seismic data without having an opportunity to attempt to benefit from those expenditures.

The Company is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting its operations or expose it to significant liabilities.
The Company's oil and natural gas exploration, production, transportation and treatment operations are subject to complex and stringent laws and regulations. In order to conduct its operations in compliance with these laws and regulations, the Company must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. The Company may incur substantial costs in order to maintain compliance with these laws and regulations. As well as recent incidents involving the release of oil and natural gas and fluids as a result of drilling activities in the United States, there have been a variety of regulatory initiatives at the federal and state levels to restrict oil and natural gas drilling operations in certain locations. Any increased regulation or suspension of oil and natural gas exploration and production, or revision or reinterpretation of existing laws and regulations, that arises out of these incidents or otherwise could result in delays and higher operating costs. Such costs or significant delays could have a material adverse effect on the Company's business, financial condition and results of operations. The Company must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent the Company is a shipper on interstate pipelines, it must comply with the tariffs of such pipelines and with federal policies related to the use of interstate capacity.

Laws and regulations governing oil and natural gas exploration and production may also affect production levels. The Company is required to comply with federal and state laws and regulations governing conservation matters, including provisions related to the unitization or pooling of the oil and natural gas properties; the establishment of maximum rates of production from wells; the spacing of wells; and the plugging and abandonment of wells. These and other laws and regulations can limit the amount of oil and natural gas the Company can produce from its wells, limit the number of wells it can drill, or limit the locations at which it can conduct drilling operations.

New laws or regulations, or changes to existing laws or regulations, may unfavorably impact the Company, could result in increased operating costs and could have a material adverse effect on the Company's financial condition and results of operations. For example, Congress has recently considered, and may continue to consider, legislation that, if adopted in its proposed form, would subject companies involved in oil and natural gas exploration and production activities to, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, and the elimination of certain U.S. federal tax preferences available with respect to oil and natural gas exploration and production activities. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") and rules promulgated thereunder could reduce trading positions in the energy futures or swaps markets and materially reduce hedging opportunities for the Company, which could adversely affect its revenues and cash flows during periods of low commodity prices, and which could adversely affect the Company's ability to restructure its hedges when it might be desirable to do so.

Additionally, state and federal regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may increase capital costs for the Company and third-party downstream oil and natural gas transporters. These and other potential regulations could increase the Company's operating costs, reduce its liquidity, delay its operations, increase direct and third-party post production costs or otherwise alter the way the Company conducts its business, which could have a material adverse effect on its financial condition, results of operations and cash flows and which could reduce cash received by or available for distribution, including any amounts paid by the Company for transportation on downstream interstate pipelines.

The Company's operations are subject to environmental and occupational safety and health laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations or result in significant costs and liabilities.
The Company's oil and natural gas exploration and production operations are subject to stringent federal, state, tribal, regional and local laws and regulations governing worker safety and health, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous

obligations that are applicable to operations, including the acquisition of permits to conduct drilling and the performance of other regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the imposition of safety and health regulations designed to protect employees from exposure to hazardous substances; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. Failure to comply with these laws and regulations may result in litigation; the assessment of sanctions, including administrative, civil or criminal penalties; the imposition of investigatory, remedial or corrective action obligations; the occurrence of delays or restrictions in permitting or performance of projects; and the issuance of injunctions limiting or preventing some or all of the Company's operations in affected areas.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of the Company's operations due to its handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to its operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, the Company could be subject to strict, joint and several strict liability for the investigation, removal or remediation of previously released materials or property contamination regardless of whether it was responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which the Company's wells are drilled and facilities where its petroleum hydrocarbons or wastes are taken for reclamation or disposal may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for contamination even in the absence of non-compliance, with environmental laws and regulations or for personal injury, natural resources damage or property damage.

In addition, the risk of accidental spills or releases could expose the Company to significant liabilities that could have a material adverse effect on the Company's financial condition or results of operations. Certain laws related to oil spills impose strict, joint and several strict liability, without regard to fault, for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by those laws, they are limited. If an oil discharge or substantial threat of discharge were to occur, the Company may be liable for costs and damages, which costs and damages could be material to its results of operations and financial position.

Changes in environmental laws and regulations occur frequently, and any changes that result delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management, or completion activities or waste handling, storage, transport, remediation or disposal, emission or discharge requirements could require significant expenditures by the Company to attain and maintain compliance and may otherwise have a material adverse effect on its results of operations, competitive position or financial condition. For example, in October 2015, the EPA issued a final rule under the Clean Air Act, lowering the NAAQS for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. The Company may not be able to recover some or any of these costs from insurance. As a result of any increased cost of compliance, the Company may decide to discontinue drilling.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays and adversely affect the Company's production.

Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons from tight formations. The Company routinely utilizes hydraulic fracturing techniques in the majority of its drilling and completion programs. The process involves the injection of water, sand and additives under pressure into targeted subsurface formations to stimulate oil and gas production. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA issued Clean Air Act final regulations in 2012 and proposed additional Clean Air Act regulations in August 2015 governing performance standards for the oil and natural gas industry; proposed in April 2015 effluent limitations guidelines that waste water from shale natural gas extraction operations must meet before discharging to a treatment plant; and issued in 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, the BLM published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands but, in September 2015, the U.S. District Court of Wyoming issued a preliminary injunction barring implementation of this rule, which order the BLM could appeal and is being separately appealed by certain environmental groups. The BLM also proposed new rules in January 2016 which seek to limit methane emissions from new and existing oil and gas operations on federal lands. The proposal would limit venting and flaring of gas, impose leak detection and repair requirements on wellsite equipment and compressors, and also require the installation of new controls on pneumatic pumps, and other activities at the wellsite such as downhole well maintenance and liquids unloading and drilling workovers and completions to reduce leaks of methane. From time to time, the U.S. 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, certain states, including Oklahoma, have adopted regulations that could impose new or more stringent permitting, disclosure, and well-construction requirements on hydraulic-fracturing operations. States could elect to prohibit hydraulic fracturing altogether, following the approach of the State of New York in 2015. Also, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. If new laws or regulations that significantly restrict or regulate hydraulic fracturing are adopted at the local, state or federal level, fracturing activities with respect to the Company’s properties could become subject to additional permit requirements, reporting requirements or operational restrictions and also to associated permitting delays and potential increases in costs. These delays or additional costs could adversely affect the determination of whether a well is commercially viable. Restrictions on hydraulic fracturing could also reduce the amount of oil, NGL or natural gas that is ultimately produced in commercial quantities from the Company’s properties.

In addition to asserting regulatory authority, certain government reviews are underway that focus on environmental issues associated with hydraulic fracturing practices. For example, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Also, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources in June 2015, which report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. However, in January 2016, the EPA's Science Advisory Board provided its comments on the draft study, indicating its concern that EPA's conclusion of no widespread, systemic impacts on drinking water sources arising from fracturing activities did not reflect the uncertainties and data limitations associated with such impacts, as described in the body of the draft report. The final version of this EPA report remains pending and is expected to be completed in 2016. Such EPA final report, when issued, as well as any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

Legislation or regulatory initiatives intended to address seismic activity are restricting and could restrict the Company's ability to dispose of saltwater produced alongside the Company's hydrocarbons, which could limit the Company's ability to produce oil and natural gas economically and have a material adverse effect on the Company's business.

Large volumes of saltwater produced alongside the Company's oil, natural gas and NGL in connection with drilling and production operations are disposed of pursuant to permits issued by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.

Furthermore, in response to recent seismic events near underground disposal wells used for the disposal by injection of produced water resulting from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have restricted, suspended or shut down the use of such disposal wells. For example, in Oklahoma, the OCC has implemented a variety of measures including adopting the National Academy of Science's "traffic light system," pursuant to which the agency reviews new disposal well applications for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted. The OCC also evaluates existing wells to assess their continued operation, or operation with restrictions, based on location relative to such faults, seismicity and other factors, with certain of such existing wells required to make frequent, or even daily, volume and pressure reports. In addition, the OCC has rules requiring operators of certain saltwater disposal wells in the state to, among other things, conduct mechanical integrity testing or make certain demonstrations of such wells' depth that, depending on the depth, could require the plugging back of such wells and/or the reduction of volumes disposed in such wells. As a result of these measures, the OCC from time to time has developed and implemented plans calling for wells within Areas of Interest where seismic incidents have occurred to restrict or suspend disposal well operations in an attempt to mitigate the occurrence of such incidents. For example, only recently, in January 2016, the OCC ordered five Arbuckle disposal wells within 10 miles of the center of earthquake activity in the Edmond area of Oklahoma to reduce disposal volumes, with wells within 3.5 miles of the activity to reduce their disposal volumes by 50 percent while the other wells within 10 miles of the activity to reduce their disposal volume by 25 percent. In addition, in January 2016, the Governor of Oklahoma announced a grant of $1.38 million in emergency funds to support earthquake research, which research is to be directed by the OCC and the Oklahoma Geological Survey. Further, on February 16, 2016, the OCC issued its largest volume reduction plan to date, covering approximately 5,281 square miles and 245 disposal wells injecting wastewater into the Arbuckle formation. In the plan, the OCC identified 76

SandRidge operated disposals wells, prescribed a four stage volume reduction schedule and set April 30, 2016 as the final date for compliance with the tiered volume reduction plan.

Additionally, the Governor of Kansas has established a task force composed of various administrative agencies to study and develop an action plan for addressing seismic activity in the state. The task force issued a recommended Seismic Action Plan calling for enhanced seismic monitoring and the development of a seismic response plan, and in November 2014, the Governor of Kansas announced a plan to enhance seismic monitoring in the state. In March 2015, the Kansas Corporation Commission issued its Order Reducing Saltwater Injection Rates. The Order identified five areas of heightened seismic concern in Harper and Sumner Counties and created a timeframe over which the maximum of 8,000 barrels of saltwater injection daily into each well. The Company and other operators of injection wells, and any injection well drilled deeper than the Arbuckle Formation was required to be plugged back in a manner approved by the Kansas Corporation Commission. On September 14, 2015, the Kansas Corporation Commission extended the Order Reducing Saltwater Injection Rates until March 13, 2016. Most recently, in February 2016, the Kansas Corporation Commission staff recommended an expansion of the areas of heightened seismic concern, which would include an additional schedule of volume reductions for Arbuckle disposal wells not previously identified in the Order released in March 2015.

Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of saltwater into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where salt water disposal activities occur or are proposed to be performed. The adoption of any new laws, regulations, or directives that restrict the Company's ability to dispose of saltwater generated by production and development activities, whether by plugging back the depths of disposal wells, reducing the volume of salt water disposed in such wells, restricting disposal well locations or otherwise, or by requiring the Company to shut down disposal wells, which could negatively affect the economic lives of the Company's properties.

The adoption and implementation of any new laws, regulations or legal directives that restrict the Company's ability to dispose of saltwater, by limiting volumes, disposal rates, disposal well locations or otherwise, or requiring the Company to shut down disposal wells, could require the Company or the operators of wells in which the Company has interests to shut in a substantial number of such wells and, accordingly, could materially and adversely affect the Company's business, financial condition and results of operations, and could have a material adverse effect on the Trust.

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that the Company produces while the physical effects of climate change could disrupt the Company's production and cause the Company to incur significant costs in preparing for or responding to those effects.
The EPA has published its findings that emissions of GHGs present a danger to public health and the environment because such gases are contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted rules that, among other things, establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards.

In addition, the EPA has adopted rules requiring the reporting of GHG emissions from oil and natural gas production and processing facilities in the United States on an annual basis. However, the adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, the Company's equipment and operations could require it to incur additional costs to monitor, report and potentially reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas that it produces. Finally, to the extent increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that could have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events, such events could have a material adverse effect on the Company's assets and operations, and potentially subject the Company to greater regulation.

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. As a result, 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 to acquire and surrender emission allowances in return for emitting those GHGs. The adoption of any legislation or regulations imposing reporting obligations on, or limiting emissions of GHGs from, equipment and operations could require costs to be incurred by the Company to reduce emissions of GHGs associated with operations or could adversely affect demand for the oil, natural gas and NGL that the Company produces and have a material adverse effect on the Company's business, financial condition and results of operations. For example, in August 2015, the EPA announced proposed rules, expected to be finalized in 2016, that would establish new controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production activities, as part of an overall effort to reduce methane emissions by up to 45 percent in 2025. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. It is not possible at this time to predict how or when the United State might impose restrictions on GHGs as a result of the international agreement agreed to in Paris. Any such legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for the oil, natural gas and NGL produced from the Company. The Company, consistent with its obligation to act as a reasonably prudent operator, may abandon a well that is uneconomic or not generating revenues from production in excess of its operating costs.

Repercussions from terrorist activities or armed conflict could harm the Company’s business.
Terrorist activities, anti-terrorist efforts or other armed conflict involving the United States or its interests abroad may adversely affect the United States and global economies and could prevent the Company from meeting its financial and other obligations. If events of this nature occur and persist, the attendant political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on prevailing oil and natural gas prices and causing a

reduction in the Company's revenues. Oil and natural gas production facilities, transportation systems and storage facilities could be direct targets of terrorist attacks, and/or operations could be adversely impacted if infrastructure integral to the Company's operations is destroyed by such an attack. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

The Company's failure to maintain an adequate system of internal control over financial reporting, could adversely affect its ability to accurately report its results.
Management is responsible for establishing and maintaining adequate internal control over financial reporting. The 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 in accordance with generally accepted accounting principles. A material weakness is a deficiency, or a combination of deficiencies, in the Company's internal control over financial reporting that results in a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. Effective internal controls are necessary for the Company to provide reliable financial reports and deter and detect any material fraud. If the Company cannot provide reliable financial reports or prevent material fraud, its reputation and operating results would be harmed. The Company maintained effective internal control over financial reporting as of December 31, 2015, as further described in Item 9A—Controls and Procedures and Management's Report on Internal Control over Financial Reporting. The Company's efforts to develop and maintain its internal controls and to remediate material weaknesses in its controls may not be successful, and it may be unable to maintain adequate controls over its financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation, including those related to acquired businesses, or other effective improvement of the Company's internal controls could harm its operating results. Ineffective internal controls could also cause investors to lose confidence in the Company's reported financial information.

Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation.
The Obama administration's budget proposals in recent years, including the budget proposal for fiscal year 2017, have included provisions eliminating certain key U.S. federal income tax preferences currently available to companies involved in oil and natural gas exploration and production. If enacted into law, these provisions would repeal certain incentives and credits applicable to taxpayers engaged in the exploration or production of oil and natural gas. These provisions include, but are not limited to (i) the repeal of current expensing of intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties, (iii) the repeal of domestic manufacturing deduction for oil and natural gas production and (iv) the increase in the amortization period from two years to seven years for geological and geophysical costs paid or incurred in connection with the exploration for, or development of, oil and natural gas within the United States. It is unclear whether any similar provisions will be included in future budget proposals, whether such provisions will actually be enacted or how soon any such provisions would become effective if enacted. The passage of any legislation relating to such proposals or any other similar changes in U.S. federal income tax laws could negatively affect the Company's financial condition and results of operations.

New derivatives legislation and regulation could adversely affect the Company's ability to hedge risks associated with its business.
The Dodd-Frank Act created a new regulatory framework for oversight of derivatives transactions by the Commodity Futures Trading Commission (the "CFTC") and the SEC. Among other things, the Dodd-Frank Act subjects certain swap participants to new capital, margin and business conduct standards. In addition, the Dodd-Frank Act contemplates that where appropriate in light of outstanding exposures, trading liquidity and other factors, swaps (broadly defined to include most hedging instruments other than futures) will be required to be cleared through a

registered clearing facility and traded on a designated exchange or swap execution facility, unless the “end-user” exception from clearing applies. The Dodd-Frank Act also established a new Energy and Environmental Markets Advisory Committee to make recommendations to the CFTC regarding matters of concern to exchanges, firms, end users and regulators with respect to energy and environmental markets and also expands the CFTC’s power to impose position limits on specific categories of swaps (excluding swaps entered into for bona fide hedging purposes).

There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. However, although the Company may qualify for exceptions, its derivatives counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the Dodd-Frank Act, which may increase the Company’s transaction costs or make it more difficult for the Company to enter into hedging transactions on favorable terms. The Company’s inability to enter into hedging transactions on favorable terms, or at all, could increase its operating expenses and put it at increased exposure to risks of adverse changes in oil and natural gas prices, which could adversely affect the predictability of cash flows from sales of oil and natural gas.

In November 2011, the CFTC finalized rules to establish a position limits regime on certain "core" physical-delivery contracts and their economically equivalent derivatives, some of which reference major energy commodities, including oil and natural gas. However, in September 2012, the District Court of the District of Columbia vacated the CFTC's rulemaking and remanded to the CFTC for further proceedings. On November 6, 2013, the CFTC re-proposed rules to establish a position limits regime on 28 "core" physical commodity contracts and their "economically equivalent" futures, options, and swaps, some of which reference major energy commodities, including oil and natural gas ("Position Limits Re-Proposal"), as well as amending the rules governing the aggregation of positions. Notably, the Position Limits Re-Proposal provides limited enumerated hedge exemptions from the position limits and a prescriptive process for requiring an exemption for non-enumerated hedges. The most recent comment period for the Position Limits Re-Proposal closed on January 22, 2015, but the final rules related to position limits are not yet in effect. To the extent the Position Limits Re-Proposal is finalized, such regulations could subject the Company or its derivatives counterparties to limits on commodity positions and thereby have an adverse effect on its ability to hedge risks associated with its business or on the cost of its hedging activity.

Cyber-attacks or other failures in telecommunications or IT systems could result in information theft, data corruption and significant disruption of the Company's business operations.

In recent years, the Company has increasingly relied on information technology systems and networks in connection with its business activities, including certain of its exploration, development and production activities. The Company relies on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to, among other things, estimate quantities of oil and gas reserves, analyze seismic and drilling information, process and record financial and operating data and communicate with employees and third parties. As dependence on digital technologies has increased, cyber incidents, including deliberate attacks and attempts to gain unauthorized access to computer systems and networks, have increased in frequency and sophistication. These threats pose a risk to the security of the Company's systems and networks, the confidentiality, availability and integrity of its data and the physical security of its employees and assets. The Company has experienced, and expects to continue to confront, attempts from hackers and other third parties to gain unauthorized access to its information technology systems and networks. Although prior cyber-attacks have not had a material adverse impact on the Company's operations or financial performance, there can be no assurance that the Company will be successful in preventing cyber-attacks or successfully mitigating their effect. Any cyber-attack could have a material adverse effect on the Company's reputation, competitive position, business, financial condition and results of operations. Cyber-attacks or security breaches also could result in litigation or regulatory action, as well as significant additional expense to implement further data protection measures.

In addition to the risks presented to the Company's systems and networks, cyber-attacks affecting oil and gas distribution systems maintained by third parties, or the networks and infrastructure on which they rely, could delay or prevent delivery to markets. A cyber-attack of this nature would be outside the Company's ability to control, but could have a material, adverse effect on the Company's business, financial condition and results of operations.

Item 1B. Unresolved Staff Comments

None.

## Item 2. Properties

Information regarding the Company’s properties is included in Item 1.

Item 3. Legal Proceedings

On April 5, 2011, Wesley West Minerals, Ltd. and Longfellow Ranch Partners, LP filed suit against the Company and SandRidge Exploration and Production, LLC (collectively, the “SandRidge Entities”) in the 83rd District Court of Pecos County, Texas. The plaintiffs, who have leased mineral rights to the SandRidge Entities in Pecos County, allege that the SandRidge Entities have not properly paid royalties on all volumes of natural gas and $CO_2$ produced from the acreage leased from the plaintiffs. The plaintiffs also allege that the SandRidge Entities have inappropriately failed to pay royalties on $CO_2$ produced from the plaintiffs’ acreage that results from the treatment of natural gas at the Century Plant. The plaintiffs seek approximately $45.5 million in actual damages for the period of time between January 2004 and December 2011, punitive damages and a declaration that the SandRidge Entities must pay royalties on $CO_2$ produced from the plaintiffs’ acreage that results from treatment of natural gas at the Century Plant. The Commissioner of the General Land Office of the State of Texas (“GLO”) is named as an additional defendant in the lawsuit as some of the affected oil and natural gas leases described in the plaintiffs’ allegations cover mineral classified lands in which the GLO is entitled to one-half of the royalties attributable to such leases. The GLO has filed a cross-claim against the SandRidge Entities asserting the same claims as the plaintiffs with respect to the leases covering mineral classified lands and seeking approximately $13.0 million in actual damages, inclusive of penalties and interest. On February 5, 2013, the Company received a favorable summary judgment ruling that effectively removes a majority of the plaintiffs’ and GLO’s claims. On April 29, 2013, the court entered an order allowing for an interlocutory appeal of its summary judgment ruling.

The plaintiffs appealed the rulings to the Texas Court of Appeals in El Paso. On November 19, 2014, that court issued its opinion, which affirmed the trial court’s summary judgment rulings in part, but reversing them in part. The Court of Appeals affirmed the summary judgment rulings in the SandRidge Entities’ favor against the GLO. The court also affirmed the summary judgment rulings in the SandRidge Entities’ favor against Wesley West Minerals, Ltd., on the largest oil and gas lease involved in the case, which accounted for much of the total damages the plaintiffs are claiming. The court reversed certain rulings on other leases, thus deciding those matters for the plaintiffs. The parties have petitioned the Supreme Court of Texas for review of the Court of Appeals’ decision.

The Company intends to continue to defend the remaining issues in the trial court, as well as future appellate proceedings. At the time of the rulings on summary judgment, the lawsuit was still in the discovery stage and, accordingly, an estimate of reasonably possible losses, if any, associated with the remaining causes of action and those rulings reversed by the Court of Appeals cannot be made until all of the facts, circumstances and legal theories relating to such claims and the SandRidge Entities’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

Between December 2012 and March 2013, seven putative shareholder derivative actions were filed in state and federal court in Oklahoma:

- Arthur I. Levine v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on December 19, 2012 in the U.S. District Court for the Western District of Oklahoma
- Deborah Depuy v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on January 22, 2013 in the U.S. District Court for the Western District of Oklahoma
- Paul Elliot, on Behalf of the Paul Elliot IRA R/O, v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant filed on January 29, 2013 in the U.S. District Court for the Western District of Oklahoma
- Dale Hefner v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on January 4, 2013 in the District Court of Oklahoma County, Oklahoma
- Rocky Romano v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on January 22, 2013 in the District Court of Oklahoma County, Oklahoma
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- Joan Brothers v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on February 15, 2013 in the U.S. District Court for the Western District of Oklahoma
- Lisa Ezell, Jefferson L. Mangus, and Tyler D. Mangus v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on March 22, 2013 in the U.S. District Court for the Western District of Oklahoma

Each lawsuit identified above was filed derivatively on behalf of the Company and names as defendants current and former directors of the Company. The Hefner lawsuit also names as defendants certain current and former directors and senior executive officers of the Company. All seven lawsuits assert overlapping claims - generally that the defendants breached their fiduciary duties, mismanaged the Company, wasted corporate assets, and engaged in, facilitated or approved self-dealing transactions in breach of their fiduciary obligations. The Depuy lawsuit also alleges violations of federal securities laws in connection with the Company allegedly filing and distributing certain misleading proxy statements. The lawsuits seek, among other relief, injunctive relief related to the Company's corporate governance and unspecified damages.

On April 10, 2013, the U.S. District Court for the Western District of Oklahoma consolidated the Levine, Depuy, Elliot, Brothers, and Ezell actions (the "Federal Shareholder Derivative Litigation") under the caption "In re SandRidge Energy, Inc. Shareholder Derivative Litigation," appointed a lead plaintiff and lead counsel, and ordered the lead plaintiff to file a consolidated complaint by May 1, 2013. On June 3, 2013, the Company and the individual defendants filed their respective motions to dismiss the consolidated complaint. On September 11, 2013, the court granted the defendants' respective motions to dismiss the consolidated complaint without prejudice, and granted plaintiffs leave to file an amended consolidated complaint. The plaintiffs filed an amended consolidated complaint on October 9, 2013, in which plaintiffs allege that: (i) the Company's former Chief Executive Officer ("CEO"), Tom Ward, breached his fiduciary duties by usurping corporate opportunities, (ii) certain of the Company's current and former directors breached their fiduciary duties of care, (iii) Mr. Ward and certain of the Company's current and former directors wasted corporate assets, (iv) certain entities allegedly affiliated with Mr. Ward aided and abetted Mr. Ward's breaches of fiduciary duties, (v) Mr. Ward and entities allegedly affiliated with Mr. Ward misappropriated the Company's confidential and proprietary information, and (vi) entities allegedly affiliated with Mr. Ward were unjustly enriched. On November 15, 2013, the Company and the individual defendants filed their respective motions to dismiss the amended consolidated complaint. On September 22, 2014, the court denied the motion to dismiss filed on behalf of the Company and the director defendants. The court also granted in part and denied in part the respective motions to dismiss filed on behalf of the other defendants.

On May 8, 2013, the court stayed the Romano action pending further order of the court. On October 29, 2014, the court granted plaintiff's application to dismiss the action without prejudice.

On September 26, 2014, the Board of Directors for the Company formed a Special Litigation Committee ("SLC"), composed of two independent and disinterested Company directors, and delegated absolute and final authority to the SLC to review and investigate the claims alleged by the plaintiffs in the Federal Shareholder Derivative Litigation and in the Hefner action, and to determine whether or how those claims should be asserted on the Company's behalf.

On October 7, 2015, the derivative plaintiffs in the Federal Shareholder Derivative Litigation, the SLC, and the individual defendants in the Federal Shareholder Derivative Litigation (Tom Ward, Jim Brewer, Everett Dobson, William Gilliland, Daniel Jordan, Roy Oliver Jr., and Jeffrey Serota), executed a Stipulation of Settlement, which would result in a partial settlement of the Federal Shareholder Derivative Litigation by settling all claims against the individual defendants, subject to certain terms and conditions, including the approval of the court. Under the terms of the proposed partial settlement, the Company would implement or agree to maintain certain corporate governance reforms, and the insurers for the individual defendants would pay $38.0 million to an escrow fund, which would be used to pay certain expenses arising from pending securities litigation and, to the extent funds remain after paying such expenses, would be paid to the Company without any further restrictions on the Company's use of such funds. The proposed partial settlement expressly provides, among other terms, that the settling defendants deny all allegations of wrongdoing and are entering into the settlement solely to avoid the costs, disruption, uncertainty, and risk of further litigation.

On October 9, 2015, the court issued an Order granting preliminary approval of the Stipulation of Settlement and, after notice and a hearing on December 18, 2015, the court issued a Final Judgment and Order on December 22, 2015, granting final approval of the Stipulation of Settlement. The partial settlement did not settle any of the derivative plaintiffs' claims against non-settling defendants WCT Resources, L.L.C., 192 Investments, L.L.C., and TLW Land & Cattle, L.P in the Federal Shareholder Derivative Litigation. On January 12, 2016, a shareholder who objected to the Stipulation of Settlement filed a notice of appeal of the court's Final Judgment and Order approving the Stipulation of Settlement.

On November 30, 2015, the court stayed the Hefner action until further order of the court. An estimate of reasonably possible losses associated with the Hefner action cannot be made at this time. The Company has not established any reserves relating to this action.

On December 5, 2012, James Glitz and Rodger A. Thornberry, on behalf of themselves and all other similarly situated stockholders, filed a putative class action complaint in the U.S. District Court for the Western District of Oklahoma against the Company and certain current and former executive officers of the Company. On January 4, 2013, Louis Carbone, on behalf of himself and all other similarly situated stockholders, filed a substantially similar putative class action complaint in the same court and against the same defendants. On March 6, 2013, the court consolidated these two actions under the caption “In re SandRidge Energy, Inc. Securities Litigation” (the “Securities Litigation”) and appointed a lead plaintiff and lead counsel. On July 23, 2013, plaintiffs filed a consolidated amended complaint, which asserts a variety of federal securities claims against the Company and certain of its current and former officers and directors, among other defendants, on behalf of a putative class of (a) purchasers of SandRidge common stock during the period from February 24, 2011 to November 8, 2012, (b) purchasers of common units of the Mississippian Trust I in or traceable to its initial public offering on or about April 12, 2011, and (c) purchasers of common units of the Mississippian Trust II in or traceable to its initial public offering on or about April 23, 2012. The claims are based on allegations that the Company, certain of its current and former officers and directors, and the Mississippian Trusts, among other defendants, are responsible for making false and misleading statements, and omitting material information, concerning a variety of subjects, including oil and natural gas reserves, the Company's capital expenditures, and certain transactions entered into by companies allegedly affiliated with the Company's former CEO Tom Ward.

On May 11, 2015, the court dismissed without prejudice plaintiffs' claims against the Mississippian Trust I and the Mississippian Trust II (together, the "Mississippian Trusts") and the underwriter defendants. On August 27, 2015, the court dismissed without prejudice plaintiffs' claims against the Company and the individual current and former officers and directors, and granted plaintiffs leave to file a second amended consolidated complaint.

On October 23, 2015, plaintiffs filed their Second Consolidated Amended Complaint in which plaintiffs assert federal securities claims against the Company and certain of its current and former officers and directors on behalf of a putative class of purchasers of SandRidge common stock during the period between February 24, 2011, and November 8, 2012. The claims are based on allegations that the Company and certain of its current and former officers and directors are responsible for making false and misleading statements, and omitting material information, concerning a variety of subjects, including oil and gas reserves, the Company's capital expenditures, and certain transactions entered into by companies allegedly affiliated with the Company's former CEO Tom Ward.

Because the Securities Litigation is in the early stages, an estimate of reasonably possible losses associated with it, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and defendants' defenses are fully disclosed and analyzed. The Company has not established any reserves relating to the Securities Litigation. Each of the Mississippian Trusts has requested that the Company indemnify it for any losses it may incur in connection with the Securities Litigation.

On July 15, 2013, James Hart and 15 other named plaintiffs filed an Amended Complaint in the United States District Court for the District of Kansas in an action undertaken individually and on behalf of others similarly situated against SandRidge Energy, Inc., SandRidge Operating Company, SandRidge Exploration and Production, LLC, SandRidge Midstream, Inc., and Lariat Services, Inc. In their Amended Complaint, plaintiffs allege that the defendants failed to properly calculate overtime pay for the plaintiffs and for other similarly situated current and former employees. The plaintiffs further allege that the defendants required the plaintiffs and other similarly situated current and former employees to engage in work-related activities without pay. The plaintiffs assert claims against the defendants for (i) violations of the Fair Labor Standards Act, (ii) violations of the Kansas Wage Payment Act, (iii) breach of contract, and (iv) fraud, and seek to recover unpaid wages and overtime pay, liquidated damages, statutory penalties, economic damages, compensatory and punitive damages, attorneys' fees and costs, and both pre- and post-judgment interest.

On October 3, 2013, the plaintiffs filed a Motion for Conditional Collective Action Certification and for Judicial Notice to the Class and a Motion to Toll the Statute of Limitations. On October 11, 2013, the defendants filed a Motion to Dismiss and a Motion to Transfer Venue to the United States District Court for the Western District of Oklahoma.

On April 2, 2014, the court granted the defendants' Motion to Dismiss and granted plaintiffs leave to file an amended complaint by April 16, 2014, which they did on such date. On July 1, 2014, the court granted plaintiffs' Motion for Conditional Collective Action Certification and for Judicial Notice to the Class, and denied plaintiffs' Motion to Toll the Statute of Limitations.

On May 27, 2015, the parties reached an agreement in principle to settle this lawsuit. Pursuant to such agreement, the Company will establish a settlement fund from which to pay participating plaintiffs' claims as well as plaintiffs' attorneys' fees. The proposed settlement agreement is subject to final negotiations between the parties and court approval. During the year ended December 31, 2015, the Company established a $5.1 million reserve for this lawsuit.

As previously disclosed, on December 18, 2013, the Company received a subpoena duces tecum from the U.S. Department of Justice in connection with an ongoing investigation of possible violations of antitrust laws in connection with the purchase or lease of land, oil or natural gas rights. The transactions that have been the subject of the inquiry date from 2012 and prior years. On April 7, 2015, the U.S. Department of Justice notified the Company that it is a target of a grand jury investigation in the Western District of Oklahoma concerning violations of federal antitrust law. The Company is continuing to respond to the government's requests in connection with the investigation. The Company is unable to predict the outcome of the government's investigation, or any range of loss that could be associated with the resolution of any possible criminal charges or civil claims that may be brought against the Company; however, any governmental action or resolution thereof could be material to the Company. The Company is cooperating with the investigation.

On June 9, 2015, the Duane & Virginia Lanier Trust, individually and on behalf of all others similarly situated, filed a putative class action complaint in the U.S. District Court for the Western District of Oklahoma against the Company and certain of its current and former officers and directors, among other defendants, on behalf of a putative class of (a) purchasers of common units of the Mississippian Trust I pursuant or traceable to its initial public offering on or about April 7, 2011, and/or at other times during the time period between April 7, 2011, and November 8, 2012 (the "Class Period"), and (b) purchasers of common units of the Mississippian Trust II pursuant or traceable to its initial public offering on or about April 17, 2012, and/or at other times during the Class Period. The claims are based on allegations that the Company, certain of its current and former officers and directors, and the Mississippian Trusts, among other defendants, are responsible for making false and misleading statements, and omitting material information, concerning a variety of subjects, including oil and natural gas reserves and the Company's capital expenditures. The Company and the other defendants intend to defend this lawsuit vigorously. This lawsuit is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this action, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the defendants' defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action. Each of the Mississippian Trusts has requested that the Company indemnify it for any losses it may incur in connection with this lawsuit.

On July 30, 2015, Barton Gernandt, Jr., individually and on behalf of all others similarly situated, filed a putative class action complaint in the U.S. District Court for the Western District of Oklahoma against the Company and certain of its current and former officers and directors, among other defendants, on behalf of a putative class comprised of all persons, except the named defendants and their immediate family members, who were participants in, or beneficiaries of, the SandRidge Energy, Inc. 401(k) Plan (the "Plan") at any time between August 2, 2012, and the present, and whose Plan accounts included investments in SandRidge common stock. The plaintiff purports to bring the action both derivatively on the Plan's behalf pursuant to ERISA §§ 409 and 502, and as a class action pursuant to Rule 23 of the Federal Rules of Civil Procedure. The plaintiff's claims are based on allegations that the defendants breached their fiduciary duties owed to the Plan and to the Plan participants by allowing the investment of the Plan's assets in SandRidge common stock when it was otherwise allegedly imprudent to do so based on the financial condition of the Company and the fact the Company's common stock was artificially inflated because, among other things, the Company materially overstated the amount of oil being produced and the ratio of oil to natural gas in one of its core holdings.

On August 19, 2015, Christina A. Cummings, individually and on behalf of all others similarly situated, filed a putative class action complaint in the U.S. District Court for the Western District of Oklahoma against the Company and certain of its current and former officers, among other defendants, on behalf of a putative class comprised of all participants for whose individual accounts the Plan held shares of SandRidge common stock from November 8, 2012, to the present, inclusive. The plaintiff purports to bring the action both derivatively on the Plan's behalf pursuant to ERISA §§ 409 and 502, and as a class action pursuant to Rule 23 of the Federal Rules of Civil Procedure. The plaintiff's claims are based on allegations that the defendants breached their fiduciary duties owed to the Plan and to the Plan participants by allowing the investment of the Plan's assets in SandRidge common stock when it was otherwise allegedly imprudent to do so based on the financial condition of the Company. On September 10, 2015, the Court consolidated this lawsuit with the Gernandt action.

On September 14, 2015, Richard A. McWilliams, individually and on behalf of all others similarly situated, filed a putative class action complaint in the U.S. District Court for the Western District of Oklahoma against the Company and certain of its current and former officers and directors, among other defendants, on behalf of a putative class comprised of all persons, except the named defendants and their immediate family members, who were participants in, or beneficiaries of, the Plan at any time between August 2, 2012, and the present, and whose Plan accounts included investments in SandRidge common stock. The plaintiff purports to bring the action both derivatively on the Plan's behalf pursuant to ERISA §§ 409 and 502, and as a class action pursuant to Rule 23 of the Federal Rules of Civil Procedure. The plaintiff's claims are based on allegations that the defendants breached their fiduciary duties owed to the Plan and to the Plan participants by allowing the investment of the Plan’s assets in SandRidge common stock when it was otherwise allegedly imprudent to do so based on the financial condition of the Company and the fact the Company’s common stock was artificially inflated because, among other things, the Company materially overstated the amount of oil being produced and the ratio of oil to natural gas in one of its core holdings. On September 24, 2015, the Court consolidated this lawsuit with the Gernandt action.

On November 24, 2015, the plaintiffs filed a Consolidated Class Action Complaint in the consolidated Gernandt action. The Company intends to defend this consolidated lawsuit vigorously. This lawsuit is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this action, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the defendants’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

On November 18, 2015, Mickey Peck, on behalf of himself and others similarly situated, filed a First Amended Collective Action Complaint in the United States District Court for the Western District of Oklahoma against SandRidge Energy, Inc., and

SandRidge Operating Company for violations of the Fair Labor Standards Act. Plaintiff alleges that the Company improperly classified certain of its consultants as independent contractors rather than as employees and, therefore, improperly paid such consultants a day rate without paying any overtime compensation. On January 14, 2016, the Court entered an Order conditionally certifying the class and providing for notice. This lawsuit is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this action, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the defendants’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

On January 12, 2016, Lisa Griggs and April Marler, on behalf of themselves and all other similarly situated, filed a putative class action petition in the District Court of Logan County, Oklahoma, against SandRidge Exploration and Production, LLC, and certain other oil and gas exploration companies. In their petition, plaintiffs assert various tort claims based upon purported damage and loss resulting from earthquakes allegedly caused by the defendants’ operations of wastewater disposal wells. Plaintiffs seek to certify a class of “all residents of Oklahoma owning real property from 2011 through the time the Class is certified.” On February 16, 2016, the defendants filed a Notice of Removal of the lawsuit to the United States District Court for the Western District of Oklahoma. This lawsuit is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this action, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the defendants’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

On February 12, 2016, Brenda Lene and Jon Darryn Lene filed a petition in the District Court of Logan County, Oklahoma, against SandRidge Exploration and Production, LLC, and certain other oil and gas exploration companies. In their petition, plaintiffs assert various tort claims based on their allegations that their home suffered damages due to earthquakes allegedly caused by the defendants’ operations of wastewater disposal wells. This lawsuit is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this action, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the defendants’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

On March 3, 2016, Brian Thieme, on behalf of himself and all others similarly situated, filed a putative class action petition in the United States District Court for the Western District of Oklahoma against SandRidge Energy, Inc. and the Company’s former CEO, Tom L. Ward, among other defendants. Plaintiff alleges that, commencing on or around December 27, 2007, and continuing until at least March 31, 2012, the defendants conspired to rig bids and depress the market for the purchases of oil and natural gas leasehold interests and properties containing producing oil and natural gas wells located in certain areas of Oklahoma, Texas, Colorado and Kansas, in violation of Sections 1 and 3 of the Sherman Antitrust Act. Plaintiff seeks to certify two separate and distinct classes of members. This lawsuit is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this action, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the defendants’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

On March 10, 2016, Don Beadles, in Trust for the Alva Synagogue Church, on behalf of himself and all others similarly situated, filed a putative class action petition in the United States District Court for the Western District of Oklahoma against SandRidge Energy, Inc. and the Company’s former CEO, Tom L. Ward, among other defendants. Plaintiff alleges that since as early as December 2007, and continuing until at least as late as March 2012 (the “Relevant Class Period”), the defendants conspired to rig bids and otherwise depress the amounts they paid to property owners for the acquisition of oil and gas leasehold interests and producing properties located in certain areas of Oklahoma, Texas, Colorado and Kansas, in violation of Sections 1 and 3 of the Sherman Antitrust Act. Plaintiff seeks to certify a class of “all persons and entities that, during the Relevant Class Period, provided or sold to one of more of the Defendants (a) oil and gas leasehold interests on their property and/or (b) the producing properties, in exchange for lease payments, including but not limited to lease bonuses.” This lawsuit is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this action, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the defendants’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

On March 24, 2016, Janet L. Lowry, on behalf of herself and all others similarly situated, filed a putative class action petition in the United States District Court for the Western District of Oklahoma against SandRidge Energy, Inc. and the Company’s former CEO, Tom L. Ward, among other defendants. Plaintiff alleges that, commencing on or around December 27, 2007, and continuing until at least March 31, 2012, the defendants conspired to rig bids and depress the price of royalty and bonus payments exchanged for purchases of oil and natural gas leasehold interests and interests in properties containing producing oil and natural gas wells located in certain areas of Oklahoma, Texas, Colorado and Kansas, in violation of Section 1 of the Sherman Antitrust Act. Plaintiff seeks to certify two separate and distinct classes of members. This lawsuit is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this action, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the defendants’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

On February 4, 2015, the staff of the SEC Enforcement Division in Washington, D.C., notified the Company that it had commenced an informal inquiry concerning the Company's accounting for, and disclosure of, its carbon dioxide delivery shortfall penalties under the terms of the Gas Treating and CO2 Delivery Agreement, dated June 29, 2008, between SandRidge Exploration and Production, LLC, and Oxy USA Inc.

Additionally, the Company received a letter from an attorney for a former employee at the Company (the "Former Employee"). In the letter, the attorney alleged, among other things, that the Former Employee had been terminated because he had objected to the levels of oil and gas reserves disclosed by the Company in its public filings. Over 85% of such reserves were calculated by an independent petroleum engineering firm. The Audit Committee of the Company's Board of Directors has retained an independent law firm to review the Former Employee's allegations and the circumstances of the Former Employee's termination. In addition, the Company reported the Former Employee's allegations to the SEC staff, which thereafter issued two subpoenas to the Company relating to the Former Employee's allegations. Counsel for the Audit Committee is responding to both of these subpoenas.

During the course of the above inquiries, the SEC issued a subpoena to the Company seeking documents relating to employment-related agreements between the Company and certain employees. The Company is cooperating with this inquiry and, after discussion with staff, the Company sent corrective letters to certain current and former employees who had entered into agreements containing language that may have been inconsistent with SEC rules prohibiting a company from impeding an individual from communicating directly with the SEC about possible securities law violations. The Company also updated its Code of Conduct and other relevant policies.

The Company continues to cooperate with the above inquiries and is unable to predict their outcome or the possible loss, if any, that could result from their potential resolution.

In addition to the litigation described above, the Company is a defendant in lawsuits from time to time in the normal course of business. While the results of litigation and claims cannot be predicted with certainty, the Company believes the reasonably possible losses of such matters, individually and in the aggregate, are not material. Additionally, the Company believes the probable final outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations, cash flows or liquidity.

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

PRICE RANGE OF COMMON STOCK

Through December 31, 2015, the Company's common stock was listed on the New York Stock Exchange ("NYSE") under the symbol "SD." The range of high and low sales prices for its common stock for the periods indicated, as reported by the NYSE, is as follows:

| | High | Low |
|---|---|---|
| 2015 | | |
| Fourth Quarter | $0.56 | $0.17 |
| Third Quarter | $0.90 | $0.25 |
| Second Quarter | $2.30 | $0.81 |
| First Quarter | $2.53 | $1.13 |
| 2014 | | |
| Fourth Quarter | $4.80 | $1.50 |
| Third Quarter | $7.20 | $4.10 |
| Second Quarter | $7.43 | $6.07 |
| First Quarter | $6.75 | $5.59 |

On March 23, 2016, there were 285 record holders of the Company's common stock.

The Company has neither declared nor paid any cash dividends on its common stock, and it does not anticipate declaring any dividends on its common stock in the foreseeable future. The Company expects to retain cash for the operation and expansion of its business, including exploration, development and production activities. In addition, the terms of the Company's indebtedness restrict its ability to pay dividends to holders of its common stock. Accordingly, if the Company's dividend policy were to change in the future, its ability to pay dividends would be subject to these restrictions and the Company's then-existing conditions, including its results of operations, financial condition, contractual obligations, capital requirements, business prospects and other factors deemed relevant by its Board of Directors.

PERFORMANCE GRAPH

The following graph compares the cumulative total return to stockholders on SandRidge common stock relative to the cumulative total returns of the S&P Oil and Gas Exploration and Production Index and the S&P 500 Index from January 1, 2011 through December 31, 2015. The graph assumes that the value of the investment in the Company's common stock and in each of the indexes was $100.00 on January 1, 2011.

The performance graph above is furnished and not filed for purposes of Section 18 of the Exchange Act and will not be incorporated by reference into any registration statement filed under the Securities Act unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

ISSUER PURCHASES OF EQUITY SECURITIES

The following table presents a summary of share repurchases made by the Company during the three-month period ended December 31, 2015.

| Period | Total Number of Shares Purchased(1) | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Program | Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program (In millions) |
|---|---|---|---|---|
| October 1, 2015 — October 31, 2015 | 153,376 | $0.50 | N/A | N/A |
| November 1, 2015 — November 30, 2015 | 9,568 | $0.37 | N/A | N/A |
| December 1, 2015 — December 31, 2015 | 10,307 | $0.17 | N/A | N/A |
| Total | 173,251 | | — | |

(1) Includes shares of common stock tendered by employees in order to satisfy tax withholding requirements upon vesting of their stock awards. Shares withheld are initially recorded as treasury shares, then immediately retired.

Item 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, the Company's selected financial information. The Company's financial information is derived from its audited consolidated financial statements for such periods. The financial data includes the results of the Company's acquisitions and divestitures, including PGC and the Rockies properties in the fourth quarter of 2015, the divestiture of the Gulf Properties in February 2014, the divestiture of the Permian Properties in February 2013, the acquisition of oil and natural gas properties in the Gulf of Mexico in June 2012, and the acquisition of oil and natural gas properties in the Gulf of Mexico from Dynamic Offshore Resources LLC in April 2012. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this report and the Company's consolidated financial statements and notes thereto contained in "Financial Statements and Supplementary Data" in Item 8 of this report. The following information is not necessarily indicative of the Company's future results.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2012 | 2011 |
| | (In thousands, except per share data) | | | | |
| Statement of Operations Data | | | | | |
| Revenues | $768,709 | $1,558,758 | $1,983,388 | $1,934,642 | $1,415,213 |
| Expenses | | | | | |
| Production | 308,701 | 346,088 | 516,427 | 477,154 | 322,877 |
| Production taxes | 15,440 | 31,731 | 32,292 | 47,210 | 46,069 |
| Cost of sales | 24,394 | 56,155 | 57,118 | 68,227 | 65,654 |
| Midstream and marketing | 26,819 | 49,905 | 53,644 | 39,669 | 66,007 |
| Construction contract | — | — | 23,349 | — | — |
| Depreciation and depletion—oil and natural gas | 319,913 | 434,295 | 567,732 | 568,029 | 317,246 |
| Depreciation and amortization—other | 47,382 | 59,636 | 62,136 | 60,805 | 53,630 |
| Accretion of asset retirement obligations | 4,477 | 9,092 | 36,777 | 28,996 | 9,368 |
| Impairment | 4,534,689 | 192,768 | 26,280 | 316,004 | 2,825 |
| General and administrative(1) | 150,166 | 122,865 | 330,425 | 241,682 | 148,643 |
| (Gain) loss on derivative contracts | (73,061) | (334,011) | 47,123 | (241,419) | (44,075) |
| Loss on settlement of contract | 50,976 | — | — | — | — |
| Loss (gain) on sale of assets | 1,491 | 10 | 399,086 | 3,089 | (2,044) |
| Total expenses | 5,411,387 | 968,534 | 2,152,389 | 1,609,446 | 986,200 |
| (Loss) income from operations | (4,642,678) | 590,224 | (169,001) | 325,196 | 429,013 |
| Other (expense) income | | | | | |
| Interest expense | (321,421) | (244,109) | (270,234) | (303,349) | (237,332) |
| Bargain purchase gain | — | — | — | 122,696 | — |
| Gain (loss) on extinguishment of debt | 641,131 | — | (82,005) | (3,075) | (38,232) |
| Other income, net | 2,040 | 3,490 | 12,445 | 4,741 | 3,122 |
| Total other expense | 321,750 | (240,619) | (339,794) | (178,987) | (272,442) |
| (Loss) income before income taxes | (4,320,928) | 349,605 | (508,795) | 146,209 | 156,571 |
| Income tax expense (benefit) | 123 | (2,293) | 5,684 | (100,362) | (5,817) |
| Net (loss) income | (4,321,051) | 351,898 | (514,479) | 246,571 | 162,388 |
| Less: net (loss) income attributable to noncontrolling interest | (623,506) | 98,613 | 39,410 | 105,000 | 54,323 |
| Net (loss) income attributable to SandRidge Energy, Inc. | (3,697,545) | 253,285 | (553,889) | 141,571 | 108,065 |
| Preferred stock dividends | 37,950 | 50,025 | 55,525 | 55,525 | 55,583 |
| (Loss applicable) income available to SandRidge Energy, Inc. common stockholders | $(3,735,495) | $203,260 | $(609,414) | $86,046 | $52,482 |

| | | | | | |
|---|---|---|---|---|---|
| (Loss) earnings per share | | | | | |
| Basic | $(7.16) | $0.42 | $(1.27) | $0.19 | $0.13 |
| Diluted | $(7.16) | $0.42 | $(1.27) | $0.19 | $0.13 |
| Weighted average number of common shares outstanding | | | | | |
| Basic | 521,936 | 479,644 | 481,148 | 453,595 | 398,851 |
| Diluted | 521,936 | 499,743 | 481,148 | 456,015 | 406,645 |

(1) Includes employee termination benefits.

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| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2012 | 2011 |
| | (In thousands) | | | | |
| Balance Sheet Data | | | | | |
| Cash and cash equivalents | $435,588 | $181,253 | $814,663 | $309,766 | $207,681 |
| Property, plant and equipment, net | $2,234,702 | $6,215,057 | $6,307,675 | $8,479,977 | $5,389,424 |
| Total assets | $2,991,155 | $7,259,225 | $7,684,795 | $9,790,731 | $6,219,609 |
| Total debt | $3,631,506 | $3,195,436 | $3,194,907 | $4,301,083 | $2,814,176 |
| Total stockholders’ (deficit) equity | $(1,187,733 ) | $3,209,820 | $3,175,627 | $3,862,455 | $2,548,950 |
| Total liabilities and stockholders’ (deficit) equity | $2,991,155 | $7,259,225 | $7,684,795 | $9,790,731 | $6,219,609 |

There have been no cash dividends declared or paid on the Company’s common stock.

## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis is intended to help the reader understand the Company's business, financial condition, results of operations, liquidity and capital resources. This discussion and analysis should be read in conjunction with other sections of this report, including: "Business" in Item 1, "Selected Financial Data" in Item 6 and "Financial Statements and Supplementary Data" in Item 8. The Company's discussion and analysis includes the following subjects:

- Overview;
- Results by Segment;
- Consolidated Results of Operations;
- Liquidity and Capital Resources;
- Valuation Allowance; and
- Critical Accounting Policies and Estimates.

### Overview

SandRidge Energy, Inc. is an energy company with principal operations in the Mid-Continent region in Oklahoma and Kansas. At December 31, 2015, the Company also owned properties in the Rockies in Colorado, which were acquired during the fourth quarter of 2015, and in west Texas. The Company sold the majority of its Gulf Properties in 2014 and its Permian Basin assets in 2013 and has used the proceeds from those transactions to reduce outstanding long-term debt and fund drilling and development in its core area of focus. See further discussion of these transactions below.

The Company also operates businesses and infrastructure systems that are complementary to its primary exploration and production activities, including gas gathering and processing facilities, marketing operations, a saltwater gathering and disposal system and an electrical transmission system. Additionally, until January 2016, the Company operated a drilling and related oilfield services business.

### Recent Events

Senior Credit Facility. During January 2016, the Company borrowed the available capacity under the senior credit facility, or $488.9 million, and such amounts remained outstanding at March 23, 2016. On March 11, 2016, the administrative agent of the senior credit facility notified the Company that the lenders had elected to reduce the borrowing base to $340.0 million pursuant to a special redetermination. On March 21, 2016, the Company notified the administrative agent that the Company would submit for the administrative agent's consideration proposed additional oil and gas properties to serve as collateral under the senior credit facility sufficient to support a borrowing base of $500.0 million. Additionally, the Company notified the administrative agent that it believed the currently pledged assets are sufficient to support a borrowing base of $500.0 million and reserved the right to exercise all other options available to remedy the borrowing base deficiency, if any. The Company has until April 20, 2016 to submit such additional properties.

Divestiture of WTO Properties and Release from Treating Agreement. On January 21, 2016, the Company paid $11.0 million in cash and transferred ownership of substantially all of its oil and natural gas properties and midstream assets located in the Piñon field in the WTO, including the PGC assets acquired in October 2015, to Occidental and was released from all past, current and future claims and obligations under an existing 30-year treating agreement between the companies. As of December 31, 2015, the Company had accrued approximately $109.9 million for penalties associated with shortfalls in meeting its delivery requirements under the agreement since it became effective in late 2012, including $34.9 million incurred for the year ended December 31, 2015.

Production, proved reserves, revenues and direct operating expenses for the oil and natural gas properties transferred in the transaction were 1.9 MMBoe, 24.6 MMBoe, $14.6 million and $41.1 million, respectively, as of and for the year ended December 31, 2015.

Acquisition of Piñon Gathering Company, LLC. In October 2015, the Company acquired the assets of and terminated a gas gathering agreement with PGC for $48.0 million cash and $78.0 million principal amount of Senior Secured Notes. PGC's assets consist of approximately 370 miles of gathering lines that support the Company's production in the Piñon field in West Texas. The transaction resulted in the termination of the Company's gas gathering agreement with PGC under which it was required to compensate PGC for any throughput shortfalls below a required minimum volume. The fair value of the consideration paid by the Company, including discount attributable to the Senior Secured Notes issued, was approximately $98.3 million and was allocated on a relative fair value basis between the assets acquired (approximately $47.3 million) and a loss on the termination of the gathering contract (approximately $51.0 million).

Acquisition of Rockies Properties. In December 2015, the Company acquired approximately 135,000 net acres in the North Park Basin, Jackson County, Colorado for approximately $191.1 million in cash, including post-closing adjustments. Also included in the acquisition were working interests in 16 wells previously drilled on the acreage. Additionally, the seller paid the Company $3.1 million for certain overriding interests retained in the properties. The Company commenced development of the acquired acreage in early 2016.

Senior Secured Notes. On June 10, 2015, the Company completed the issuance of $1.25 billion in aggregate principal amount of Senior Secured Notes, which bear interest at a fixed rate of 8.75% per annum, payable semi-annually, with the principal due upon maturity. Net proceeds from the issuance were approximately $1.21 billion, a portion of which was used to repay amounts outstanding at that time under the Company's senior credit facility.

Repurchase, Exchange and Redemption of Senior Unsecured Notes. In August 2015, the Company repurchased approximately $250.0 million of its 8.75% Senior Notes due 2020, 7.5% Senior Notes due 2021, 8.125% Senior Notes due 2022, and 7.5% Senior Notes due 2023 (collectively, "Senior Unsecured Notes") for approximately $94.5 million cash and issued $275.0 million aggregate principal amount of 8.125% Convertible Senior Notes due 2022 and 7.5% Convertible Senior Notes due 2023 (collectively, "Convertible Senior Unsecured Notes") in exchange for $275.0 million aggregate principal amount of its Senior Unsecured Notes. In October 2015, the Company repurchased $100.0 million of its Senior Unsecured Notes for approximately $30.0 million cash, and issued $300.0 million aggregate principal amount of Convertible Senior Unsecured Notes in exchange for $300.0 million aggregate principal amount of its Senior Unsecured Notes. Through December 31, 2015, holders of the Company's Convertible Senior Unsecured Notes have redeemed approximately $255.3 million in aggregate principal amount ($73.7 million net of discount and including holders' conversion feature liabilities) of the Convertible Senior Unsecured Notes for approximately 92.8 million shares of the Company's common stock. The repurchases and exchanges of the Company's Senior Unsecured Notes and subsequent redemptions of the Company's Convertible Senior Unsecured Notes resulted in an aggregate gain on extinguishment of debt of approximately $623.2 million.

During the second quarter of 2015, the Company issued to a holder of its 7.5% Senior Notes due 2021 and 8.125% Senior Notes due 2022, approximately 28.0 million shares of the Company's common stock in exchange for an aggregate $50.0 million principal amount of the notes and as payment for the interest accrued thereon since the last interest payment date. The exchange resulted in a gain on extinguishment of debt of $17.9 million.

2014 and 2013 Divestitures

Gulf of Mexico and Gulf Coast Properties. On February 25, 2014, the Company sold subsidiaries that owned the Gulf Properties, for approximately $702.6 million, net of working capital adjustments and post-closing adjustments, and the buyer's assumption of approximately $366.0 million of related asset retirement obligations. The Company retained a 2% overriding royalty interest in certain exploration prospects. The Company used the proceeds from the sale to fund its drilling in the Mid-Continent. Additionally, the Company settled a portion of its existing oil derivative contracts in January and February 2014 prior to their respective maturities to reduce volumes hedged in proportion to the anticipated reduction in daily production volumes due to the sale, which resulted in the Company making cash payments of approximately $69.6 million. This transaction did not result in a significant alteration of the relationship between the Company's capitalized costs and proved reserves and, accordingly, the Company recorded the proceeds as a reduction of its full cost pool with no gain or loss on the sale.

Production, revenues and expenses, including direct operating expenses, depletion, accretion of asset retirement obligations and general and administrative expenses, for the Gulf Properties included in the Company's results for the years ended December 31, 2014, and 2013 were as follows:

| | Year Ended December 31, | |
|---|---|---|
| | 2014(1) | 2013 |
| Production (MBoe) | 1,321 | 10,082 |
| Revenues (in thousands) | $90,920 | $627,236 |
| Expenses (in thousands) | $63,674 | $491,991 |

(1) Includes activity through February 25, 2014, the date of sale.

Permian Properties. On February 26, 2013, the Company sold the Permian Properties for $2.6 billion. The Company used a portion of the sale proceeds to fund the redemption of approximately $1.1 billion aggregate principal amount of outstanding senior notes, discussed in “Liquidity and Capital Resources,” and used the remaining proceeds to fund its capital expenditures in the Mid-Continent and for general corporate purposes. The Company recorded a non-cash loss on the sale of $398.9 million, of which $71.7 million was allocated to noncontrolling interests. Additionally, the Company settled a portion of its existing oil derivative contracts in February 2013 prior to their respective maturities to reduce volumes hedged in proportion to the anticipated reduction in daily production volumes due to the sale, which resulted in cash payments of approximately $29.6 million.

Production, revenues and direct operating expenses of the Permian Properties were as follows as of and for the year ended December 31, 2013:

| | Year Ended December 31, 2013(1) |
|---|---|
| Production (MBoe) | 1,148 |
| Revenues (in thousands) | $68,027 |
| Direct operating expenses (in thousands) | $17,453 |

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(1) Includes activity through February 26, 2013, the date of sale.

2015 Operational Activities

Operational highlights for 2015 include the following:

- Total production for 2015 was comprised of approximately 32.0% oil, 51.2% natural gas and 16.8% NGLs compared to 37.6% oil, 49.3% natural gas and 13.1% NGLs in 2014.
- Reduced the total rigs drilling to four (no rigs drilling disposal wells) at December 31, 2015 from 35 (including four drilling disposal wells) at December 31, 2014.
- Drilled 161 wells, excluding salt water disposal wells, in the Mid-Continent area. Mid-Continent properties contributed approximately 26.6 MMBoe, or 88.5%, of the Company’s total production in 2015 compared to approximately 23.4 MMBoe, or 80.9%, in 2014.
- Discontinued drilling and oilfield services operations in the Permian area as a result of declining oil prices and decreased demand for drilling and oilfield services in the region.

Outlook

The Company established a 2016 capital expenditures budget of approximately $285.0 million, with approximately $262.0 million designated for exploration and production activities. These amounts reflect a decrease from total 2015 capital expenditures of 59% and a decrease from 2015 exploration and production capital expenditures of 60%.

The Company’s estimated proved reserve volumes were 324.6 MMBoe at December 31, 2015 based on internal estimates using the SEC-mandated historical 12-month unweighted average pricing at such date, which were $46.79 per barrel of oil and $2.59 per Mcf of natural gas. Replacing the January 1, 2015, February 1, 2015 and March 1, 2015 price components with actual January 1, 2016, February 1, 2016 and March 1, 2016 benchmark commodities prices, the 12-month unweighted average prices would have been $42.77 per barrel of oil and $2.40 per Mcf of natural gas. If the Company’s December 31, 2015 reserves estimates were made using the reduced 12-month average prices, and without regard to additions or other further revisions to reserves other than as a result of such pricing changes, the Company’s internally estimated proved reserves as of December 31, 2015 would decrease by approximately 6%, and PV-10 would decrease by approximately $229.0 million, primarily as a result of the loss of proved undeveloped locations. As a result of continued depressed commodity prices, the Company’s final capital plan for 2016, developed in March 2016, contemplates a smaller drilling program than that assumed in the development of the December 31, 2015 reserve report. If commodity pricing falls short of the Company’s current expectations or rebounds to a level supportive of more drilling, the Company may change its 2016 capital expenditure plans again. However, the Company’s management does not expect these short term changes to negatively impact the Company’s ability to develop all of its December 31, 2015 proved undeveloped locations within a five year time frame. All reserve estimates for periods after December 31, 2015 provided in this Form 10-K were determined by Company reservoir engineers and, accordingly, have not been fully assessed by independent petroleum consultants.

In light of impacts to the Company’s financial position resulting from declining industry conditions and the Company’s leverage position, the Company has engaged advisors to assist with the evaluation of strategic alternatives and has engaged in discussion with certain stakeholders regarding strategic alternatives to restructure its indebtedness. The Company is also focused on cost reductions, including the identification of non-core assets for potential sale. There can be no assurance that any restructuring transaction will occur as a result of such discussions with stakeholders, that the terms of any potential restructuring transaction or other transactions would be acceptable to the Company or that such transactions would be successful. As a result of these uncertainties and the likelihood of a restructuring or reorganization, management has concluded that there is substantial doubt regarding the Company’s ability to continue as a going concern as it is currently structured.

Results by Segment

During the years ended December 31, 2015, 2014 and 2013 the Company operated in three reportable business segments: exploration and production, drilling and oilfield services and midstream services, each of which offer different products and services. The exploration and production segment is engaged in the exploration and production of oil and natural gas properties and includes the activities of the Royalty Trusts. The drilling and oilfield services segment, which was substantially discontinued during January 2016, was engaged in the contract drilling of oil and natural gas wells and provided various oilfield services. The midstream services segment is engaged in the purchasing, gathering, treating and selling of natural gas and coordinates the delivery of electricity for the Company's exploration and production operations in the Mid-Continent.

Management evaluates the performance of the Company's business segments based on income (loss) from operations. Results of these measurements provide important information to the Company about the activity, profitability and contributions of each of the Company's lines of business. Results for the Company's business segments for the years ended December 31, 2015, 2014 and 2013 are discussed below.

Exploration and Production Segment

The Company generates the majority of its consolidated revenues and cash flow from the production and sale of oil, natural gas and NGLs. The Company's revenues, profitability and future growth depend substantially on prevailing prices for oil, natural gas and NGLs and on the Company's ability to find and economically develop and produce its reserves. The primary factors affecting the financial results of the Company's exploration and production segment are the quantity of oil, natural gas and NGLs it produces, the prices the Company receives for its production and changes in the fair value of its commodity derivative contracts. Prices for oil, natural gas and NGLs fluctuate widely and are difficult to predict. To provide information on the general trend in pricing, the average annual NYMEX prices for oil and natural gas for recent years are presented in the table below:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2012 | 2011 |
| Oil (per Bbl) | $48.75 | $92.91 | $98.05 | $94.15 | $95.11 |
| Natural gas (per Mcf) | $2.62 | $4.26 | $3.73 | $2.83 | $4.03 |

In order to reduce the Company's exposure to price fluctuations, the Company historically has entered into commodity derivative contracts for a portion of its anticipated future oil and natural gas production as discussed in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk." Reducing the Company's exposure to price volatility helps mitigate the risk that it will not have adequate funds available for its capital expenditure programs.

Set forth in the table below is financial, production and pricing information for the exploration and production segment for the years ended December 31, 2015, 2014 and 2013.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Results (in thousands) | | | |
| Revenues | | | |
| Oil | $439,927 | $977,269 | $1,393,360 |
| NGL | 72,440 | 126,759 | 80,555 |
| Natural gas | 195,067 | 316,851 | 346,363 |
| Other | 12 | 2,194 | 14,202 |
| Inter-segment revenue | (12) | (173) | (320) |
| Total revenues | 707,434 | 1,422,900 | 1,834,160 |
| Operating expenses | | | |
| Production | 310,233 | 348,387 | 519,546 |
| Production taxes | 15,440 | 31,731 | 32,292 |
| Depreciation and depletion—oil and natural gas | 319,913 | 434,295 | 567,732 |
| Accretion of asset retirement obligations | 4,477 | 9,092 | 36,777 |
| Impairment | 4,473,787 | 164,779 | — |
| (Gain) loss on derivative contracts | (73,061) | (334,011) | 47,123 |
| Loss on settlement of contract | 50,976 | — | — |
| (Gain) loss on sale of assets | (25) | (39) | 398,543 |
| Other operating expenses | 67,601 | 54,950 | 169,638 |
| Total operating expenses | 5,169,341 | 709,184 | 1,771,651 |
| (Loss) income from operations | $(4,461,907) | $713,716 | $62,509 |
| | | | |
| Production data | | | |
| Oil (MBbls) | 9,600 | 10,876 | 14,279 |
| NGL (MBbls) | 5,044 | 3,794 | 2,291 |
| Natural gas (MMcf) | 92,105 | 85,697 | 103,233 |
| Total volumes (MBoe) | 29,995 | 28,953 | 33,776 |
| Average daily total volumes (MBoe/d) | 82.2 | 79.3 | 92.5 |
| Average prices—as reported(1) | | | |
| Oil (per Bbl) | $45.83 | $89.86 | $97.58 |
| NGL (per Bbl) | $14.36 | $33.41 | $35.16 |
| Natural gas (per Mcf) | $2.12 | $3.70 | $3.36 |
| Total (per Boe) | $23.59 | $49.08 | $53.89 |
| Average prices—including impact of derivative contract settlements(2) | | | |
| Oil (per Bbl) | $76.80 | $94.18 | $98.90 |
| NGL (per Bbl) | $14.36 | $33.41 | $35.16 |
| Natural gas (per Mcf) | $2.45 | $3.58 | $3.46 |
| Total (per Boe) | $34.51 | $50.36 | $54.79 |

(1) Prices represent actual average prices for the periods presented and do not include the impact of derivative transactions.

(2) Excludes settlements of commodity derivative contracts prior to their contractual maturity.

For a discussion of reserves, PV-10 and reconciliation to Standardized Measure, see “Business—Business Segments and Primary Operations—Proved Reserves” in Item 1 of this report.

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The table below presents production by area of operation for the years ended December 31, 2015, 2014 and 2013 and illustrates the impact of (i) the Company's continued development of its Mid-Continent assets, (ii) the Company's sale in February 2014 of the Gulf Properties, and (iii) the sale of the Permian Properties in February 2013.

| | Year Ended December 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2015 | | | 2014 | | | 2013 | | |
| | Production (MBoe) | % of Total Production | | Production (MBoe) | % of Total Production | | Production (MBoe) | % of Total Production | |
| Mid-Continent | 26,558 | 88.5 | % | 23,423 | 80.9 | % | 17,783 | 52.7 | % |
| Gulf of Mexico / Gulf Coast | — | — | % | 1,321 | 4.6 | % | 10,082 | 29.8 | % |
| Permian Basin | 1,567 | 5.2 | % | 2,076 | 7.2 | % | 3,366 | 10.0 | % |
| Other - west Texas | 1,870 | 6.3 | % | 2,133 | 7.3 | % | 2,545 | 7.5 | % |
| Total | 29,995 | 100.0 | % | 28,953 | 100.0 | % | 33,776 | 100.0 | % |

Revenues

Exploration and production segment revenues from oil, natural gas and NGL sales decreased by a combined $713.4 million, or 50.2% for the year ended December 31, 2015 compared to 2014. Approximately $664.3 million of the total net decrease was due to a decline in the average prices received primarily for oil production, and to a lesser extent, natural gas and NGL production. The remaining decrease of $49.1 million is due largely to a decrease in oil production, which was partially offset by increases in natural gas and NGL production. The decline in oil production resulted primarily from natural declines in existing producing wells and the decrease in wells drilled during 2015 compared to 2014.

Exploration and production segment revenues from oil, natural gas and NGL sales decreased by a combined $399.4 million, or 21.9% for the year ended December 31, 2014 compared to 2013. Approximately $337.9 million of the total net decrease resulted from a 4.8 MMBoe, or 14.3% decrease in combined production, stemming largely from the sale of the Gulf Properties in February 2014. As illustrated in the table above, the decrease in production resulting from the sale of the Gulf Properties was partially offset by increased production in the Mid-Continent as the Company focused its development efforts in this area. The remainder of the decrease in exploration and production segment revenues was primarily due to a decline in the average price received for oil production.

Operating Expenses

Production expense includes the costs associated with the Company's exploration and production activities, including, but not limited to, lease operating expense and treating costs. Production expenses for 2015 decreased $38.2 million, or 11.0% from 2014. Production costs per Boe decreased to $10.34 per Boe for the 2015 period from $12.03 per Boe in 2014, primarily as a result of (i) the sale of the Gulf Properties in February 2014, which had higher production costs inherent with offshore operations, and (ii) a decrease in well activity as a result of fewer new wells being brought on production and a reduction in workover activity in 2015 in conjunction with an increase in combined production for the year ended December 31, 2015 compared to 2014. Production expenses decreased $171.2 million, or 32.9%, in 2014 compared to 2013, primarily due to the decrease in total production as described above and a decrease in production costs per Boe. For the year ended December 31, 2014, production expense was $12.03 per Boe, down from the rate for 2013 of $15.38 per Boe, primarily as a result of the sale of the Gulf Properties in February 2014.

Production taxes decreased by $16.3 million, or 51.3%, for 2015, compared to 2014, primarily due to the decrease in oil, natural gas and NGL revenues. Production taxes as a percentage of oil, natural gas and NGL revenue were consistent at approximately 2.2% for both 2015 and 2014. Production taxes as a percentage of oil, natural gas and NGL revenue increased to approximately 2.2% for 2014 from 1.8% for 2013 as taxable production from the Mid-Continent partially replaced non-taxable production from the Gulf Properties sold in February 2014.

Depreciation and depletion for the Company’s oil and natural gas properties decreased by $114.4 million for the year ended December 31, 2015, compared to 2014. This decrease largely resulted from a reduction in the average depreciation and depletion rate per Boe to $10.67 for 2015 from $15.00 for 2014, primarily due to (i) the sale of the Gulf Properties in February 2014 (ii) full cost ceiling impairments recorded in 2015 and (iii) changes in future production and planned capital expenditures that occurred in conjunction with the year end 2014 budgeting and reserves estimation processes. Depreciation and depletion for the Company’s oil and natural gas properties decreased by $133.4 million for 2014, compared to 2013, largely as a result of the decrease in the Company’s combined production volumes for the 2014 period as well as a decrease in the average depreciation and depletion rate per Boe to $15.00 for 2014 from $16.81 in 2013. The decrease in the depreciation and depletion rate is primarily due to (i) the sale of the Gulf Properties in February 2014 (ii) full cost ceiling impairment recorded in the first quarter of 2014, and (iii) changes in future production and planned capital expenditures.

Accretion of asset retirement obligations decreased $4.6 million for the year ended December 31, 2015, compared to 2014, and decreased $27.7 million for the year ended December 31, 2014, compared to 2013, primarily due to Fieldwood's assumption of asset retirement obligations associated with the Gulf Properties sold in February 2014.

Impairment of $4.5 billion for the year ended December 31, 2015 was due to full cost ceiling limitations recognized in each quarter of 2015, which resulted primarily from the significant decrease in oil prices, and to a lesser extent, natural gas prices, that began in the latter half of 2014 and continued throughout 2015. Impairment of $164.8 million for the year ended December 31, 2014 was due to a full cost ceiling limitation resulting from the divestiture of the Gulf Properties in the first quarter of 2014 as the present value of future net revenues associated with the Gulf Properties exceeded the associated reduction to the full cost pool. There was no full cost ceiling impairment for the year ended December 31, 2013.

While it is difficult to project future impairment write-downs in light of numerous variables involved, the following analysis illustrates the impact of lower commodities pricing on impairment charges. Applying the reduced twelve-month average prices described above under "Outlook" to the December 31, 2015 ceiling test for impairment, the Company estimates the impairment charge for the quarter would have increased by approximately $229.0 million. Accordingly, at this time, the Company expects to incur a further ceiling test impairment write-down in the first quarter of 2016.

The Company recorded a (gain) loss on commodity derivative contracts of $(73.1) million, $(334.0) million and $47.1 million for the years ended December 31, 2015, 2014 and 2013, respectively, as reflected in income from operations for the exploration and production segment, which include net cash (receipts) payments upon settlement of $(327.7) million, $32.3 million and $(0.8) million, respectively. Included in the net cash payments (receipts) for the years ended December 31, 2014 and 2013 are $69.6 million and $29.6 million, respectively, of cash payments related to settlements of commodity derivative contracts with contractual maturities after the year in which they were settled ("early settlements") as a result of the sale of the Gulf Properties in February 2014 and the Permian Properties in February 2013, respectively.

The Company's derivative contracts are not designated as accounting hedges and, as a result, gains or losses on commodity derivative contracts are recorded each quarter as a component of operating expenses. Internally, management views the settlement of derivative contracts at contractual maturity as adjustments to the price received for oil and natural gas production to determine "effective prices." Gains or losses on early settlements and losses related to amendments of contracts are not considered in the calculation of effective prices. In general, cash is received on settlement of contracts due to lower oil and natural gas prices at the time of settlement compared to the contract price for the Company's oil and natural gas price swaps, and cash is paid on settlement of contracts due to higher oil and natural gas prices at the time of settlement compared to the contract price for the Company's oil and natural gas price swaps.

Loss on settlement of contract resulted from the termination of the Company's gas gathering agreement with PGC under which it was required to compensate PGC for any throughput shortfalls below a required minimum volume. See "Overview-Recent Events" above and see "Note 3—Acquisitions and Divestitures" and "Note 4—Variable Interest Entities" to the Company's consolidated financial statements in Item 8 of this report for additional discussion of the acquisition of PGC and the PGC gathering agreement.

The Company recorded a loss on the sale of assets of $398.9 million for the year ended December 31, 2013 as a result of the sale of the Permian Properties in February 2013. No gain or loss was recognized for the sale of the Gulf

Properties in February 2014. See “Note 3—Acquisitions and Divestitures” to the Company’s consolidated financial statements in Item 8 of this report for additional discussion of these transactions.

See “Consolidated Results of Operations” below for a discussion of other operating expenses.

Drilling and Oilfield Services Segment

The Company historically has drilled for its own account in northwestern Oklahoma, Kansas and west Texas and for other oil and gas companies, primarily in west Texas, through its drilling and oilfield services subsidiary. Additionally, the Company’s oilfield services business provided pulling units, trucking, rental tools, location and road construction and roustabout services. The financial results of the Company’s drilling and oilfield services segment depended primarily on demand and prices that could be charged for its services. On a consolidated basis, drilling and oilfield service revenues earned and expenses incurred in performing services for third parties, including third-party working interests in wells the Company operates, were included in drilling and services revenues and cost of sales. Drilling and oilfield service revenues earned and expenses incurred in performing services for the Company's own account were eliminated in consolidation. The primary factors affecting the results of the Company's drilling and oilfield services segment were the rates received on rigs drilling for third parties, the number of days drilling for third parties and the amount of oilfield services provided to third parties.

Demand for the Company's drilling and oilfield services declined significantly during the latter half of 2014 and throughout 2015 due to downward trends in oil and natural gas prices experienced in those periods. In the first quarter of 2015, as a result of decreased demand for drilling services in the Permian region and the Company's fulfillment of its drilling obligation with the Permian Trust in November 2014, the Company decided to discontinue all remaining drilling and oilfield services operations in the Permian region. No wells were drilled for third parties after the first quarter of 2015. The Company discontinued substantially all remaining drilling and oilfield services operations in January 2016.

Set forth in the table below is financial and operational information for the drilling and oilfield services segment for the years ended December 31, 2015, 2014 and 2013.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Results (in thousands) | | | |
| Revenues | $67,358 | $192,944 | $187,456 |
| Inter-segment revenue | (45,234) | (116,856) | (120,815) |
| Total revenues | 22,124 | 76,088 | 66,641 |
| Operating expenses | 44,478 | 86,225 | 95,692 |
| Impairment | 37,645 | 27,427 | 11,104 |
| Loss from operations | $(59,999) | $(37,564) | $(40,155) |
| | | | |
| Drilling rig statistics | | | |
| Average number of operational rigs owned during the period | 11.0 | 27.0 | 29.0 |
| Average number of rigs working for third parties | — | 4.8 | 4.4 |
| Number of days drilling for third parties | — | 1,749 | 1,603 |
| Average drilling revenue per day per rig drilling for third parties(1) | $— | $14,985 | $14,610 |
| | | | |
| Rig status as of December 31 | | | |
| Working for SandRidge(2) | 2 | 10 | 11 |
| Working for third parties | — | — | 6 |
| Idle(3) | — | 15 | 10 |
| Total operational | 2 | 25 | 27 |
| Non-operational(4) | — | 2 | 3 |
| Total rigs | 2 | 27 | 30 |

(1) Represents revenues from rigs working for third parties, excluding stand-by revenue, divided by the total number of days such drilling rigs were used by third parties during the period, excluding revenues for related rental equipment.

(2) Rigs drilling for SandRidge at December 31, 2015, were released in January 2016 and are included in assets held for sale in other current assets on the accompanying consolidated balance sheet at December 31, 2015.

(3) The Company's rigs are primarily intended to drill for its own account; as such, the number of idle rigs does not significantly impact the consolidated results of operations.

(4) Non-operational rigs at December 31, 2014 were stacked. Non-operational rigs at December 31, 2013 were held for sale.

Drilling and oilfield services segment revenues and expenses decreased $54.0 million and $41.7 million, respectively, for the year ended December 31, 2015 compared to 2014, primarily due to a decrease in revenue from third party working interests for work performed on wells in which the Company also has an interest, as well as a decrease in the average number of rigs working for third parties.

Drilling and oilfield services segment revenues increased $9.4 million for the year ended December 31, 2014 compared to 2013, primarily due to an increase in revenue from third party working interests for work performed on wells in which the Company also has an interest, as well as an increase in the average number of rigs working for third parties. Drilling and oilfield services segment operating expenses decreased $9.5 million during the year ended December 31, 2014 compared to 2013 due primarily to an increased focus on capital discipline by management as well as the closure of the drilling fluids services business in the Permian region during the fourth quarter of 2014 upon fulfillment of the Permian Trust drilling obligation.

During 2015 and 2014, the Company recorded impairments of approximately $37.6 million and $27.4 million, respectively, on certain drilling assets in order to adjust their carrying values to fair value after classifying certain assets as held for sale or determining that the future use of assets held and used was limited.

Midstream Services Segment

Midstream services segment revenues consist primarily of revenue from gas marketing, which is a very low-margin business, and revenues from coordinating the delivery of electricity to the Company’s exploration and production operations in the Mid-Continent area. The primary factors affecting the results of the Company’s midstream services segment are the quantity of natural gas the Company gathers, treats and markets and the prices it pays and receives for natural gas as well as the rates charged and volumes delivered by the electrical transmission system.

Gas Marketing. On a consolidated basis, midstream and marketing revenues include natural gas sold to third parties and the fees the Company charges to gather, compress and treat this natural gas. Gas marketing operating costs represent payments made to third parties for the proceeds from the sale of natural gas owned by such parties, net of any applicable margin, and actual costs the Company charges to gather, compress and treat the natural gas. In general, natural gas purchased and sold by the Company’s midstream services segment is priced at a published daily or monthly index price. Midstream gas services are primarily undertaken to realize incremental margins on natural gas purchased at the wellhead and to provide value-added services to customers.

Provision of Electricity. The Company constructed an electrical transmission system in the Mid-Continent area to provide electricity for use in the Company’s exploration and production operations at a lower cost than electricity provided by on-site generation. On a consolidated basis, revenues and expenses from the electrical transmission system relate to electricity provided to third-party working interest owners in Company operated wells in the Mid-Continent.

Gas Treating Plants. At December 31, 2015, the Company owned two gas treating plants in west Texas, one of which was transferred to Occidental in January 2016 in the transaction discussed under “Overview- Recent Events” along with substantially all of the Company’s assets located in the Piñon field. The treating plant retained by the Company has been fully impaired due to lack of planned use.

Set forth in the table below is financial information for the midstream services segment for the years ended December 31, 2015, 2014 and 2013.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Results (in thousands) | | | |
| Operating revenues | $81,083 | $142,987 | $156,640 |
| Construction contract | — | — | 23,349 |
| Inter-segment revenue | (47,274) | (87,593) | (100,529) |
| Total revenues | 33,809 | 55,394 | 79,460 |
| Operating expenses | 41,879 | 63,927 | 73,744 |
| Construction contract | — | — | 23,349 |
| Impairment | 7,148 | 561 | 3,934 |
| Loss from operations | $(15,218) | $(9,094) | $(21,567) |

| | | | |
|---|---|---|---|
| Gas Marketed | | | |
| Volumes (MMcf) | 6,631 | 7,343 | 8,006 |
| Price per Mcf | $2.43 | $4.18 | $3.56 |

Midstream services segment operating revenues and expenses decreased $21.6 million and $22.0 million, respectively, for the year ended December 31, 2015 compared to the same period in 2014. These decreases were primarily due to (i) a change in the fee structure for electrical usage during the second quarter of 2014, (ii) a decrease in the average price received for natural gas purchased and marketed in west Texas of $1.75 per Mcf as well as a decrease in volumes purchased and marketed of 712 MMcf in 2015 compared to 2014, and (iii) a decrease in gas compressor rentals in 2015 compared to 2014.

Midstream services segment operating revenues and expenses, excluding construction contract revenue and expenses decreased $0.7 million and $9.8 million, respectively, for the year ended December 31, 2014 compared to the same period in 2013. These decreases were primarily due to a change in the fee structure for electrical usage during the second quarter of 2014. The decrease in revenues during 2014 compared to 2013 due to the fee structure change was partially offset by (i) an increase in electrical transmission services provided to third-party working interest owners in the Mid-Continent, (ii) an increase of $0.62 per Mcf in the average price received for natural gas purchased and marketed in west Texas, and (iii) an increase in gas compressor and generator rentals.

During the second quarter of 2013, the Company substantially completed the construction of a series of electrical transmission expansion and upgrade projects for a third party and, as a result, recognized construction contract revenue and costs equal to $23.3 million. For more information about these projects, see “Note 11— Construction Contract” to the Company’s consolidated financial statements in Item 8 of this report.

Midstream services segment expenses for the years ended December 31, 2015, 2014 and 2013 include impairments of $7.1 million, $0.6 million and $3.9 million, respectively, primarily on generators, various other equipment, and its natural gas treating plants in west Texas due to their limited use. All natural gas produced in the WTO during 2015, 2014 and 2013 was processed at the Century Plant subject to the terms of the Company’s 30-year treating agreement with Occidental, which contained minimum $CO_2$ delivery requirements.

Consolidated Results of Operations

Revenues

The Company’s consolidated revenues for the years ended December 31, 2015, 2014 and 2013 are presented in the table below.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In thousands) | | |
| Revenues | | | |
| Oil, natural gas and NGL | $707,434 | $1,420,879 | $1,820,278 |
| Drilling and services | 22,124 | 76,088 | 66,586 |
| Midstream and marketing | 33,809 | 55,658 | 58,304 |
| Construction contract | — | — | 23,349 |
| Other | 5,342 | 6,133 | 14,871 |
| Total revenues(1) | $768,709 | $1,558,758 | $1,983,388 |

(1) Includes $57.0 million, $150.4 million and $199.3 million of revenues attributable to noncontrolling interests in consolidated variable interest entities (“VIEs”), after considering the effects of intercompany eliminations, for the years ended December 31, 2015, 2014 and 2013, respectively.

The Company’s primary sources of revenue are discussed in “Results by Segment.” See discussion of oil, natural gas and NGL revenues under “Results by Segment—Exploration and Production Segment,” discussion of drilling and services revenues under “Results by Segment—Drilling and Oilfield Services Segment” and discussion of significant midstream and marketing and construction contract revenues under “Results by Segment—Midstream Services Segment.”

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Expenses

The Company's consolidated expenses for the years ended December 31, 2015, 2014 and 2013 are presented below.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In thousands) | | |
| Expenses | | | |
| Production | $308,701 | $346,088 | $516,427 |
| Production taxes | 15,440 | 31,731 | 32,292 |
| Cost of sales | 24,394 | 56,155 | 57,118 |
| Midstream and marketing | 26,819 | 49,905 | 53,644 |
| Construction contract | — | — | 23,349 |
| Depreciation and depletion—oil and natural gas | 319,913 | 434,295 | 567,732 |
| Depreciation and amortization—other | 47,382 | 59,636 | 62,136 |
| Accretion of asset retirement obligations | 4,477 | 9,092 | 36,777 |
| Impairment | 4,534,689 | 192,768 | 26,280 |
| General and administrative | 137,715 | 113,991 | 207,920 |
| Employee termination benefits | 12,451 | 8,874 | 122,505 |
| (Gain) loss on derivative contracts | (73,061) | (334,011) | 47,123 |
| Loss on settlement of contract | 50,976 | — | — |
| Loss on sale of assets | 1,491 | 10 | 399,086 |
| Total expenses(1) | $5,411,387 | $968,534 | $2,152,389 |

(1) Includes $679.9 million, $51.0 million and $157.0 million of expenses attributable to noncontrolling interests in consolidated VIEs, after considering the effects of intercompany eliminations, for the years ended December 31, 2015, 2014 and 2013, respectively. The expenses attributable to noncontrolling interest in consolidated VIEs include $655.9 million and $29.9 million of allocated full cost ceiling impairment for the years ended December 31, 2015 and 2014, respectively, and $71.7 million of allocated loss on sale of assets associated with the sale of the Permian Properties for the year ended December 31, 2013.

See discussion of production expenses, production taxes, depreciation and depletion—oil and natural gas, accretion of asset retirement obligations, impairment, (gain) loss on derivative contracts, loss on settlement of contract and loss on sale of assets under "Results by Segment—Exploration and Production Segment," discussion of cost of sales and impairment under "Results by Segment— Drilling and Oilfield Services Segment" and discussion of midstream and marketing and construction contract expense and impairment under "Results by Segment—Midstream Services Segment."

Other impairment expense not discussed within "Results by Segment" for the year ended December 31, 2015, includes a $15.4 million impairment on property located in downtown Oklahoma City, Oklahoma to adjust the carrying value of the property to the price for which the Company sold the property in 2015 as well as $0.7 million in impairment to adjust the carrying value of certain gathering and compression equipment to fair value after determining its future use was limited. Other impairment expense not discussed within "Results by Segment" for the year ended December 31, 2013, primarily consists of $2.9 million in impairment of a corporate asset based on plans to sell this asset in 2013, and an $8.3 million impairment on certain pipe inventory, natural gas compressors, and a $CO_2$ compressor station after determining that their future use was limited. See "Note 8—Impairment" to the Company's consolidated financial statements in Item 8 of this report for additional information regarding the Company's impairments.

General and administrative expenses increased $23.7 million, or 20.8%, for the year ended December 31, 2015 compared to 2014 due primarily to (i) an increase of $14.6 million in professional services costs, including legal and consulting fees, (ii) an increase of $5.0 million due to a legal settlement recorded in 2015, and (iii) a $4.0 million increase in net payroll costs, primarily resulting from a decrease in capitalized salary costs.

General and administrative expenses decreased $93.9 million, or 45.2%, for the year ended December 31, 2014 compared to 2013 due primarily to decreases of (i) $44.5 million in compensation, (ii) $22.2 million in costs related to a stockholder consent solicitation that occurred in 2013, (iii) $9.8 million in professional services costs, (iv) $3.8 million in promotional and advertising costs, and (v) $5.5 million in other corporate support costs. The decreases in compensation, professional services costs, promotional and advertising and corporate support costs primarily resulted from corporate cost cutting measures and a decrease in headcount during 2014.

Employee termination benefits of $12.5 million for the year ended December 31, 2015 represent severance costs incurred primarily as a result of (i) a reduction in force (ii) severance costs associated with the departure of an executive officer and other senior officers and (iii) discontinuing all remaining drilling and oilfield services operations in the Permian region in 2015. Employee termination benefits of $8.9 million for the year ended December 31, 2014 represent severance costs incurred primarily in conjunction with the sale of the Gulf Properties. Employee termination benefits of $122.5 million for the year ended December 31, 2013 represent severance costs associated with former Company executives. Of the total employee termination benefits in 2013, approximately $99.3 million, including amounts associated with the accelerated vesting of restricted stock awards, were attributable to the Company’s former Chairman and CEO.

Other Income (Expense), Taxes and Net (Loss) Income Attributable to Noncontrolling Interest

The Company’s other income (expense), taxes and net (loss) income attributable to noncontrolling interest for the years ended December 31, 2015, 2014 and 2013 are reflected in the table below.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In thousands) | | |
| Other income (expense) | | | |
| Interest expense | $(321,421) | $(244,109) | $(270,234) |
| Gain (loss) on extinguishment of debt | 641,131 | — | (82,005) |
| Other income, net | 2,040 | 3,490 | 12,445 |
| Total other income (expense) | 321,750 | (240,619) | (339,794) |
| (Loss) income before income taxes | (4,320,928) | 349,605 | (508,795) |
| Income tax expense (benefit) | 123 | (2,293) | 5,684 |
| Net (loss) income | (4,321,051) | 351,898 | (514,479) |
| Less: net (loss) income attributable to noncontrolling interest | (623,506) | 98,613 | 39,410 |
| Net (loss) income attributable to SandRidge Energy, Inc. | $(3,697,545) | $253,285 | $(553,889) |

Interest expense for the years ended December 31, 2015, 2014 and 2013 consisted of the following:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In thousands) | | |
| Interest expense | | | |
| Interest expense on debt | $304,020 | $254,475 | $277,746 |
| Amortization of debt issuance costs, discounts and premium | 15,014 | 9,954 | 11,127 |
| Write off of debt issuance costs | 7,108 | — | — |
| Loss on long-term debt derivatives | 10,377 | — | — |
| Loss on interest rate swaps | — | — | 14 |
| Capitalized interest | (14,018) | (19,718) | (16,691) |
| Total | 322,501 | 244,711 | 272,196 |
| Less: interest income | (1,080) | (602) | (1,962) |
| Total interest expense | $321,421 | $244,109 | $270,234 |

Total interest expense increased $77.3 million for the year ended December 31, 2015 compared to 2014, primarily due to interest expense associated with the $1.25 billion in Senior Secured Notes issued in June 2015. This increase was partially offset by a decrease in interest paid on Senior Unsecured Notes that were repurchased or converted into shares of the Company’s common stock in 2015 as well as the loss recognized due to an increase in the fair value of derivatives embedded in certain of the Company’s long-term debt during the year ended December 31, 2015. Total interest expense decreased $26.1 million for the year ended

December 31, 2014 compared to 2013, primarily due to a reduction in interest expense associated with the senior notes repurchased and redeemed in the first quarter of 2013.

The Company recognized a gain on extinguishment of debt of $641.1 million for the year ended December 31, 2015, primarily in connection with (i) the exchange of $575.0 million in aggregate principal of the Company's Senior Unsecured Notes for Convertible Senior Unsecured Notes in 2015, (ii) the repurchase of $350.0 million in aggregate principal of the Company's Senior Unsecured Notes for approximately $124.5 million in cash, (iii) the exchange of approximately $50.0 million aggregate principal of the Company's 7.5% senior unsecured notes due 2021 and 8.125% senior unsecured notes due 2022 for shares of the Company's common stock during 2015, and (iv) conversions of the Company's Convertible Senior Unsecured Notes into shares of the Company's common stock during 2015.

The Company recognized a loss on extinguishment of debt of $82.0 million for the year ended December 31, 2013 in connection with the redemption of the Company's 9.875% Senior Notes due 2016 and 8.0% Senior Notes due 2018. The loss on extinguishment represents the premium paid to purchase the notes and the expense incurred to write off of the remaining unamortized debt issuance costs associated with the notes.

See "Note 12—Long-Term Debt" to the Company's consolidated financial statements in Item 8 of this report for additional discussion of the Company's long-term debt transactions.

The Company's tax expense and effective tax rate for the year ended December 31, 2015 continue to be low as a result of the valuation allowance against its net deferred tax asset. The Company's income tax benefit of $2.3 million for the year ended December 31, 2014 is primarily related to a reduction in the Company's gross unrecognized tax benefits following a favorable outcome pertaining to the Company's state income tax audits in the amount of $1.3 million as well as a reduction in federal alternative minimum tax ("AMT") associated with the tax year ended December 31, 2014 in the amount of $1.2 million. With respect to the AMT, the Company reduced each of the current tax liability and corresponding deferred tax asset upon finalizing and filing the Company's federal income tax return for the year ended December 31, 2014. As a result of reducing the deferred tax asset, the Company decreased its valuation allowance against its net deferred tax asset by $1.2 million. The Company reported income tax expense of $5.7 million for the year ended December 31, 2013, primarily related to AMT associated with the tax year ended December 31, 2013. The Company recorded a current tax liability and a corresponding deferred tax asset each in the amount of approximately $3.8 million at December 31, 2013. As a result of recording this deferred tax asset, the Company increased its valuation allowance against its net deferred tax asset by approximately $3.8 million. Also included in the income tax expense for the year ended December 31, 2013, is $2.4 million of current state income tax, which is partially offset by a reduction to the liability associated with unrecognized tax benefits.

Net (loss) income attributable to noncontrolling interest represents the portion of (loss) income attributable to third-party ownership in the Company's consolidated VIEs and subsidiaries. The net loss attributable to noncontrolling interest for the year ended December 31, 2015 includes full cost ceiling impairments attributable to noncontrolling interest of $655.9 million compared to a full cost ceiling impairment attributable to noncontrolling interest of $29.9 million in 2014. Revenues for the Royalty Trusts also decreased in the 2015 periods compared to the 2014 periods largely as a result of a decrease in average prices received for production, natural declines in production and a reduction in the average number of producing wells attributable to the Royalty Trusts' royalty interest, as uneconomic wells were shut-in due to continued depressed commodity pricing. Additionally, net gains recorded on the Royalty Trusts' derivative contracts decreased in 2015 compared to 2014, primarily due to the expiration of the Permian Trust's derivative contracts in the first quarter of 2015. The Company fulfilled its drilling obligations to the Mississippian Trust I in the second quarter of 2013, to the Permian Trust in the fourth quarter of 2014 and to the Mississippian Trust II in the first quarter of 2015. No further wells will be drilled for the Royalty Trusts.

Net income attributable to noncontrolling interest increased to $98.6 million for the year ended December 31, 2014 compared to $39.4 million in 2013 due primarily to (i) net gains recognized on the Royalty Trusts' derivative contracts during 2014 compared to net losses recognized during 2013 and (ii) the recognition of a full cost ceiling impairment attributable to noncontrolling interest of $29.9 million in 2014 compared to the recognition of a loss on the sale of the Permian Properties attributable to noncontrolling interest of $71.7 million in 2013. These increases were partially offset by a decrease in revenues in 2014 compared to 2013 largely as a result of declining production for the Mississippian Trust I and the Mississippian Trust II.

Liquidity and Capital Resources

As of December 31, 2015, the Company's cash and cash equivalents were $435.6 million, including $7.8 million attributable to the Company's consolidated VIEs which is available to satisfy only obligations of the VIEs. The Company had approximately $3.6 billion in total debt outstanding and $11.0 million in outstanding letters of credit with no amount outstanding under its senior credit facility at December 31, 2015. As of and for the year ended December 31, 2015, the Company was in compliance with applicable covenants under its senior credit facility and outstanding senior notes. As of March 23, 2016, the Company's cash and cash equivalents were approximately $691.7 million, including $7.8 million attributable to the Company's consolidated VIEs.

At December 31, 2015 the senior credit facility had a borrowing base of $500.0 million that was undrawn. During January 2016, the Company borrowed the available capacity under the senior credit facility, or $488.9 million, and such amounts remained outstanding at March 23, 2016. As of March 23, 2016, the proceeds of the borrowed funds under the senior credit facility were held by the Company in a securities account. On each such date, the Company had, $11.0 million and $10.4 million, respectively, in outstanding letters of credit secured by the senior credit facility, which reduce availability under the senior credit facility on a dollar for dollar basis. On March 11, 2016, the administrative agent of the senior credit facility notified the Company that the lenders had elected to reduce the borrowing base to $340.0 million pursuant to a special redetermination. On March 21, 2016, the Company notified the administrative agent that the Company would submit for the administrative agent's consideration proposed additional oil and gas properties to serve as collateral under the senior credit facility sufficient to support a borrowing base of $500.0 million. Additionally, the Company notified the administrative agent that it believed the currently pledged assets are sufficient to support a borrowing base of $500.0 million and reserved the right to exercise all other options available to remedy the borrowing base deficiency, if any. The Company has until April 20, 2016 to submit such additional properties. Continued low oil and natural gas prices or further declines in such prices could result in further proposed reduction in the size of the borrowing base under the senior credit facility, or an inability to borrow thereunder, which would further limit capital expenditures.

The Company's primary sources of liquidity and capital resources are proceeds from the issuance of debt securities, cash flows from operating activities, borrowings under the senior credit facility, proceeds from monetizations of assets and the issuance of equity securities. The Company's primary uses of capital are expenditures related to its oil and natural gas properties, such as costs related to the drilling and completion of wells, the acquisition of oil and natural gas properties and other fixed assets, interest payments on its outstanding debt, the repayment or repurchase of long-term debt, and the payment of dividends on its outstanding convertible perpetual preferred stock if, and when, the Company elects to pay such dividends in cash. Historically, the Company has availed itself of regular access to the capital and credit markets as part of its growth plan. However, as a result of sustained depressed commodity prices, the capital markets that the Company has historically accessed are currently constrained to such an extent that debt or equity capital raises are practically unfeasible. If the debt and equity capital markets do not improve, the Company may be unable to implement its drilling and development plans or otherwise carry out its business strategy as expected.

The Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, each of which depend on numerous factors beyond the Company's control such as overall oil and natural gas production and inventories in relevant markets, economic conditions, the global political environment, regulatory developments and competition from other energy sources. Oil and natural gas prices historically have been volatile and may be subject to significant fluctuations in the future. For example, from January 2011 through December 2015, the highest month end NYMEX settled price for oil was $113.93 per Bbl and the lowest was $37.04 per Bbl. Oil prices dropped sharply during the latter half of 2014 and have continued to decline throughout 2015 and into 2016, and settled as low as $26.21 per Bbl in February 2016. For natural gas, from January 2011 through December 2015, the highest month end NYMEX settled price was $5.56 per MMBtu and the lowest was $2.03 per MMBtu. Declines in market price for production directly reduce the Company's cash flow from operations and indirectly impacts its other potential sources of funds described above. While the Company's derivative arrangements serve to mitigate a portion of the effect of this price volatility on its cash flows, this extended period of depressed commodity prices has limited the Company's ability to add meaningful volumes to its hedge positions. If the current depressed oil or natural gas prices persist for a prolonged period or further decline, they would have a material adverse effect on the Company's financial position, results of operations, cash flows and quantities of oil, natural gas and NGL reserves that may be economically produced, likely resulting in further full cost pool ceiling impairments.

The Company's 2016 budget for capital expenditures is approximately $285.0 million, representing a 59% reduction from the Company's actual capital expenditures in 2015. The Company expects to fund its near term capital and debt service requirements and working capital needs with cash on hand ($435.6 million at December 31, 2015), cash flows from operations and net amounts drawn under its senior credit facility during 2016.

In light of impacts to the Company's financial position resulting from declining industry conditions and the Company's leverage position, the Company has engaged advisors to assist with the evaluation of strategic alternatives, which may include, but not be limited to, seeking a restructuring, amendment or refinancing of existing debt through a private restructuring or reorganization under Chapter 11 of the Bankruptcy Code. The Company is also focused on cost reductions, including the identification of non-core assets for potential sale. There can be no assurance that any restructuring transaction will occur as a result of such discussions with stakeholders, that the terms of any potential restructuring transaction or other transactions would be acceptable to the Company or that such transactions would be successful. As a result of these uncertainties and the likelihood of a restructuring or reorganization, management has concluded that there is substantial doubt regarding the Company’s ability to continue as a going concern as it is currently structured.

On February 16, 2016, the Company elected to defer interest payments then due with respect to its 7.5% Senior Notes due 2023 and its Senior Convertible Notes due 2023 (collectively, the “2023 Notes”). On March 15, 2016, the Company made a payment of approximately $22 million in satisfaction of its obligations under the 2023 Notes. Further, on March 16, 2016, the Company made approximately $28.4 million in interest payments then due with respect to its 7.5% Senior Notes due 2021.

In consideration of the events described above, the report of the independent registered public accounting firm that accompanies the audited consolidated financial statements for the year ended December 31, 2015 contains an explanatory paragraph regarding substantial doubt as to the Company’s ability to continue as a going concern. Inclusion of such an explanatory paragraph constitutes a covenant violation under the senior credit facility agreement. The senior credit facility agreement provides for a 30-day grace period for a breach of this covenant. If the Company does not obtain a waiver of this covenant or otherwise cure this event within 30 calendar days of the issuance of the consolidated financial statements, the lenders under the senior credit facility will be able to accelerate the maturity of the debt. Any acceleration of the obligations under the senior credit facility would result in a cross-default and potential acceleration of the Company’s other outstanding long-term debt. Currently, the Company has no contractual maturities of long-term debt prior to 2020, provided, however, that if on October 15, 2019, the aggregate outstanding principal amount of the Company’s unsecured 8.75% Senior Notes due 2020 exceeds $100.0 million, the Senior Secured Notes will mature on October 16, 2019.

Working Capital

At December 31, 2015, the Company had a working capital surplus of $236.7 million compared to a surplus of $47.5 million at December 31, 2014. Current assets decreased by $157.8 million and current liabilities decreased by $347.1 million at December 31, 2015 compared to December 31, 2014. The increase in current assets is primarily due to a $254.3 million increase in cash and cash equivalents, resulting largely from the receipt of $1.21 billion in net proceeds from the issuance of the Senior Secured Notes in June 2015, which were partially used to fund capital expenditures, the acquisition of the Rockies assets, the acquisition of and termination of a gas gathering agreement with PGC and debt repurchases. The increase in cash was partially offset by a decrease of $207.1 million in the net asset position of the Company’s current derivative contracts and a decrease of $202.7 million in accounts receivable, largely resulting from fluctuations in the timing and amount of collections of receivables. The change in current liabilities is primarily due to a decrease of $255.0 million in accounts payable and accrued expenses largely due to (i) a reduction in accrued capital expenditures resulting from a decrease in the number of drilling rigs operating on the Company’s properties, (ii) a decrease in revenue payable to third party owners in wells operated by the Company due largely to declining average prices received for oil, gas and NGLs, and (iii) other changes due primarily to fluctuations in the timing and amount of the payment of expenditures related to exploration and production operations during the year ended December 31, 2015.

Cash Flows

The Company’s cash flows for the years ended December 31, 2015, 2014 and 2013 are presented in the following table and discussed below:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In thousands) | | |
| Cash flows provided by operating activities | $373,537 | $621,114 | $868,630 |
| Cash flows (used in) provided by investing activities | (1,039,640) | (857,241) | 1,070,356 |

| | | | |
|---|---|---|---|
| Cash flows provided by (used in) financing activities | 920,438 | (397,283) | (1,434,089) |
| Net increase (decrease) in cash and cash equivalents | $254,335 | $(633,410) | $504,897 |

Cash Flows from Operating Activities

The Company’s operating cash flow is primarily influenced by the prices the Company receives for its oil, natural gas and NGLs, the quantity of oil, natural gas and NGLs it sells, settlements of derivative contracts, and third-party demand for its drilling rigs and oilfield services and the rates it is able to charge for these services. The Company’s cash flows from operating activities are also impacted by changes in working capital.

Net cash provided by operating activities for the year ended December 31, 2015 decreased by $247.6 million, or 39.9% compared to 2014 primarily due to a reduction in revenues from oil, natural gas and NGLs, largely resulting from a decrease in average prices received for the Company’s production. The decrease in revenues was partially offset by gains received on the settlement of commodity derivative contracts and, to a lesser extent, a reduction in operating expenses during the year ended December 31, 2015.

Net cash provided by operating activities for the year ended December 31, 2014 decreased by $247.5 million, or 28.5% compared to 2013 primarily due to a decrease in revenues from oil, natural gas and NGL production resulting from the sale of the Gulf Properties in February 2014, as well as changes in operating assets and liabilities during 2014, primarily related to the timing of cash receipts and disbursements.

Cash Flows from Investing Activities

The Company dedicates and expects to continue to dedicate a substantial portion of its capital expenditure program toward the exploration for and production of oil and natural gas. These capital expenditures are necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and natural gas industry.

During the year ended December 31, 2015, cash flows used in investing activities largely consisted of capital expenditures, excluding acquisitions, as well as cash paid for the North Park acquisition and the PGC assets acquired. During the year ended December 31, 2014, cash flows used in investing activities resulted from capital expenditures, excluding acquisitions, of approximately $1.6 billion, which were partially offset by proceeds from the sale of assets of $714.5 million, primarily generated by the sale of the Gulf Properties. During 2013, the Company received proceeds of $2.6 billion from the sale of the Permian Properties, which were partially offset by capital expenditures during the period.

Capital Expenditures. The Company’s capital expenditures, on an accrual basis, by segment for the years ended December 31, 2015, 2014 and 2013 are summarized below:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In thousands) | | |
| Capital expenditures | | | |
| Exploration and production | $656,022 | $1,508,100 | $1,319,012 |
| Drilling and oilfield services | 4,632 | 18,385 | 7,125 |
| Midstream services | 21,556 | 44,606 | 55,706 |
| Other | 19,405 | 37,798 | 42,040 |
| Capital expenditures, excluding acquisitions | 701,615 | 1,608,889 | 1,423,883 |
| Acquisitions | 241,165 | 18,384 | 17,028 |
| Total | $942,780 | $1,627,273 | $1,440,911 |

Capital expenditures, excluding acquisitions, decreased by $907.3 million for the year ended December 31, 2015 compared to 2014, primarily due to a decrease in drilling and leasehold expenditures. The number of drilling rigs operating on the Company’s properties decreased to four rigs at December 31, 2015 from 35 rigs at December 31, 2014. Capital expenditures, excluding acquisitions, increased by $185.0 million for the year ended December 31, 2014 compared to 2013, primarily due to an increase in drilling and leasehold expenditures in the Mid-Continent area.

During the years ended December 31, 2014 and 2013, the Company received payments for drilling carries from Atinum MidCon I, LLC’s (“Atinum”) and Repsol E&P USA, Inc. of approximately $205.6 million and $408.0 million, respectively, which directly offset the Company’s capital expenditures for the respective periods. As of December 31, 2014, both Atinum and Repsol had fully funded their drilling carry commitments.

During the fourth quarter of 2015, the Company acquired (i) all of the assets of PGC for approximately $47.3 million and (ii) approximately 135,000 net acres and 16 existing oil and natural gas wells in the North Park Basin of the Rockies, in Jackson County, Colorado for approximately $191.1 million in cash, including post-closing adjustments. The seller of the North Park Basin properties also paid the Company $3.1 million for certain overriding interests retained in the properties, which slightly offset acquisition expenditures.

Cash Flows from Financing Activities

The Company’s financing activities provided $920.4 million in cash for the year ended December 31, 2015 compared to using $397.3 million of cash in 2014. The change of $1.3 billion is due primarily to (i) the issuance of $1.25 billion in Senior Secured Notes in June 2015, which was partially offset by $124.5 million in cash paid for the repurchase of debt, and debt issuance costs incurred of $53.2 million, (ii) a decrease of $55.5 million in noncontrolling interest distributions, and (iii) a decrease of $44.3 million in preferred dividends paid in cash during the 2015 period compared to the 2014 period. The decrease in cash dividends paid was primarily due to payment of the semi-annual 7.0% preferred share dividend in May 2015 and the semi-annual 8.5% preferred share dividend in August 2015 in shares of the Company’s common stock, suspension of the 7.0% preferred share dividend prior to the November semi-annual payment, and conversion of the 6.0% preferred shares to common shares in December 2014. Additionally, during the year ended December 31, 2014, the Company paid $111.3 million, net of $0.5 million in broker fees and commissions, to repurchase shares of the Company’s common stock, as noted below, and $44.1 million for the early settlement of financing derivatives as a result of the sale of the Gulf Properties. These payments were partially offset by proceeds from the sale of Royalty Trust units of $22.1 million.

The Company’s financing activities used $397.3 million in cash for the year ended December 31, 2014 compared to using $1.4 billion of cash in 2013. This decrease is due primarily to the redemption of $1.1 billion of senior notes as well as the $62.0 million premium paid in connection with the redemption of these notes during the year ended December 31, 2013, and a decrease of $24.3 million in treasury stock purchases as a result of a reduction in shares of restricted stock that were traded for taxes upon vesting during 2014 compared to 2013. Partially offsetting these decreases were payments in 2014 of $111.3 million, net of $0.5 million in broker fees and commissions, to repurchase shares of the Company’s common stock, as noted below, and $44.1 million for the early settlement of financing derivatives as a result of the sale of the Gulf Properties.

Share Repurchase Program. On September 4, 2014, the Company announced that its Board of Directors had approved a program to repurchase up to $200.0 million of the Company's common stock. Payments for shares repurchased under the program have been funded using the Company's working capital. During the year ended December 31, 2014, 27.4 million shares were repurchased under the program for approximately $111.3 million, net of broker fees and commissions, and were immediately retired. The Company did not repurchase any shares of its common stock under the share repurchase program in 2015 and does not currently anticipate repurchasing additional shares under the share repurchase program in 2016. See “Note 16—Equity” to the Company’s consolidated financial statements in Item 8 of this report for additional discussion of the share repurchase program.

Indebtedness

Long-term debt consists of the following at December 31, 2015 (in thousands):

| | |
|---|---|
| Senior credit facility | $— |
| 8.75% Senior Secured Notes due 2020, including mandatory prepayment feature liabilities of $2,941, and net of $29,842 discount | 1,301,098 |
| Senior Unsecured Notes | |
| 8.75% Senior Notes due 2020, net of $3,269 discount | 392,666 |
| 7.5% Senior Notes due 2021, including a premium of $1,944 | 759,711 |
| 8.125% Senior Notes due 2022 | 527,737 |
| 7.5% Senior Notes due 2023, net of $1,989 discount | 541,572 |
| Convertible Senior Unsecured Notes | |
| | 82,294 |

| | |
|---|---|
| 8.125% Convertible Senior Notes due 2022, including holder conversion feature liabilities of $21,874, and net of $180,751 discount | |
| 7.5% Convertible Senior Notes due 2023, including holder conversion feature liabilities of $7,481, and net of $59,549 discount | 26,428 |
| Total debt | $3,631,506 |

The indentures governing the senior notes contain covenants imposing certain restrictions on the Company’s activities, including, but not limited to, limitations on the incurrence of indebtedness, payment of dividends, investments, asset sales, certain asset purchases, transactions with related parties and consolidations or mergers. As of and during the year ended December 31, 2015, the Company was in compliance with all of the covenants contained in the indentures governing its outstanding senior notes.

Senior Credit Facility. At December 31, 2015, the Company had no amount outstanding under the senior credit facility and $11.0 million in outstanding letters of credit, which reduced the availability under the senior credit facility to $488.9 million. As of and during the year ended December 31, 2015, the Company was in compliance with all applicable financial covenants under the senior credit facility.

The amount the Company may borrow under its senior credit facility is limited to a borrowing base, and is subject to periodic redeterminations. The Company’s borrowing base is generally redetermined in April and October of each year. The borrowing base is determined based upon the discounted present value of future cash flows attributable to the Company’s proved reserves. Because the value of the Company’s proved reserves is a key factor in determining the amount of the borrowing base, a decrease in such value, whether due to declining commodity prices or a reduction in the Company’s development of reserves would likely cause a reduction in the borrowing base. On June 10, 2015, in connection with an amendment to the senior credit agreement, as discussed further below, the borrowing base was reduced to $500.0 million from $900.0 million, which resulted in the write off of approximately $4.9 million of capitalized debt issuance costs. The borrowing base remained unchanged as a result of the October 2015 redetermination. The next scheduled redetermination is expected to take place in April 2016; however, as discussed further below, in March 2016 the borrowing base was reduced to $340.0 million pursuant to a special redetermination.

On June 10, 2015, concurrent with the issuance and sale of $1.25 billion in aggregate principal amount of its Senior Secured Notes, discussed below, the Company and its lenders amended the credit agreement to, among other things, (i) eliminate financial covenants requiring maintenance of certain levels for the ratio of total net debt to EBITDA and the ratio of EBITDA to interest expense, (ii) amend the financial covenant requiring maintenance of the ratio of total secured debt under the senior credit facility to EBITDA to 2.00:1.00 from 2.25:1.00 at quarter end and (iii) increase the permitted incurrence of additional junior debt, which may be secured, to an amount not to exceed $1.75 billion from $500.0 million. On August 13, 2015, the senior credit facility was amended to allow the Company to redeem or purchase Senior Unsecured Notes for up to $200.0 million in cash subject to certain limitations and on October 16, 2015, concurrent with the October borrowing base redetermination discussed above, the senior credit facility was further amended to increase the amount of Senior Unsecured Notes the Company may redeem or purchase for cash to $275.0 million from $200.0 million.

The amended senior credit facility is available to be drawn on subject to limitations based on its terms, including the Company’s ability to make representations and warranties contained therein regarding the value of the Company’s assets versus its liabilities, and compliance with certain financial covenants, including maintenance of agreed upon levels for the (i) ratio of total secured debt under the senior credit facility to EBITDA described above and (ii) ratio of current assets to current liabilities, which must be at least 1.0:1.0 at each quarter end. For the purpose of the current ratio calculation, any amounts available to be drawn under the senior credit facility are included in current assets, and unrealized assets and liabilities resulting from mark-to-market adjustments on the Company’s commodity derivative contracts are disregarded. The senior credit facility matures on the earlier of March 2, 2020 and 91 days prior to the earliest date of any maturity under or mandatory offer to repurchase the Company’s currently outstanding senior notes. Quarterly, the Company pays a commitment fee assessed at an annual rate of 0.5% on any available portion of the senior credit facility.

The amended senior credit agreement permits the Company and certain of its subsidiaries to incur additional indebtedness in an aggregate principal amount not to exceed $1.75 billion, which may be secured solely by collateral securing the senior credit facility on a junior lien basis. Any junior lien debt shall be subject to the terms and conditions set forth in an intercreditor agreement, the terms of which are subject to the approval of the lenders, and shall mature no earlier than January 21, 2020. The borrowing base under the senior credit facility will be reduced by $0.25 for every $1.00 of junior debt incurred in excess of $1.50 billion. At December 31, 2015, the Company had incurred $1.3 billion in junior lien debt as a result of the issuance of the Senior Secured Notes in June 2015 and October 2015 and entered into an intercreditor agreement in connection therewith.

In January 2016, the Company borrowed all of its remaining available capacity under the senior credit facility, or $488.9 million. On March 11, 2016, the administrative agent notified the Company that the lenders had elected to reduce the borrowing base to $340.0 million from $500.0 million pursuant to a special redetermination. On March 21, 2016, the Company notified the administrative agent that the Company would submit for the administrative agent’s consideration proposed additional oil and gas properties to serve as collateral under the senior credit facility sufficient to support a borrowing base of $500.0 million. Additionally, the Company notified the administrative agent that it believed the currently pledged assets are sufficient to support a borrowing base of $500.0 million and reserved the right to exercise all other options available to remedy the borrowing base deficiency, if any. The Company has until April 20, 2016 to submit such additional properties.

Senior Secured Notes. On June 10, 2015, the Company completed the issuance of $1.25 billion in aggregate principal amount of its Senior Secured Notes, which bear interest at a fixed rate of 8.75% per annum, payable semi-annually, with the principal due upon maturity. An additional $78.0 million principal amount of Senior Secured Notes was issued as partial consideration for the Company’s acquisition of and cancellation of a gas gathering agreement with PGC in October 2015. The

Senior Secured Notes are redeemable, in whole or in part, prior to their maturity at specified redemption prices and are jointly and severally guaranteed unconditionally, in full, on a second-priority secured basis by certain of the Company's wholly owned subsidiaries. Pursuant to the indenture, the Senior Secured Notes will mature on June 1, 2020; provided, however, that if on October 15, 2019, the aggregate outstanding principal amount of the Company's unsecured 8.75% Senior Notes due 2020 exceeds $100.0 million, the Senior Secured Notes will mature on October 16, 2019.

The Senior Secured Notes are secured by second-priority liens on all of the Company's and certain of the Company's wholly owned subsidiaries' assets that secure the senior credit facility on a first-priority basis; provided, however, the security interest in those assets that secure the Senior Secured Notes and the guarantees will be contractually subordinated to liens thereon that secure the senior credit facility and certain other permitted indebtedness. Consequently, the Senior Secured Notes and the guarantees will be effectively subordinated to the senior credit facility and such other indebtedness to the extent of the value of such assets. The Senior Secured Notes issued in conjunction with the acquisition of and termination of the gas gathering agreement with PGC were issued at a discount that is being amortized into interest expense over the term of the Senior Secured Notes.

Senior Unsecured Notes. The Company's Senior Unsecured Notes bear interest at a fixed rate per annum, payable semi-annually, with the principal due upon maturity. Certain of the Senior Unsecured Notes were issued at a discount or a premium. The discount or premium is amortized to interest expense over the term of the respective series of Senior Unsecured Notes. The Senior Unsecured Notes are redeemable, in whole or in part, prior to their maturity at specified redemption prices and are jointly and severally guaranteed unconditionally, in full, on an unsecured basis by certain of the Company's wholly owned subsidiaries. The Senior Unsecured Notes have a variety of maturities, the first of which is in 2020 and the latest of which is in 2023.

Convertible Senior Unsecured Notes. The Company's 8.125% Convertible Senior Notes due 2022 and 7.5% Convertible Senior Notes due 2023 are guaranteed by the same guarantors that guarantee the Senior Unsecured Notes and are subject to covenants and bear payment terms substantially identical to those of the corresponding series of Senior Unsecured Notes of similar tenor, other than the conversion features, described further below, and the extension of the final maturity by one day. The Convertible Senior Unsecured Notes were issued at a discount that is being amortized to interest expense over the term of the respective series of Convertible Senior Unsecured Notes.

The Convertible Senior Unsecured Notes are convertible into shares of Company common stock at the option of holders or, subject to compliance with certain conditions, the Company. In addition, if a holder exercises its right to convert on or prior to the first anniversary of the issuance of the Convertible Senior Unsecured Notes, such holder will receive an early conversion payment in an amount equal to the amount of 18 months of interest payable on the applicable series of converted Convertible Senior Unsecured Notes. If a holder exercises its right to convert after the first anniversary of the issuance of the Convertible Senior Unsecured Notes but on or prior to the second anniversary of the issuance of such Convertible Senior Unsecured Notes, such holder will receive an early conversion payment in an amount equal to 12 months of interest payable on the applicable series of converted Convertible Senior Unsecured Notes. No early conversion payment will be made upon a mandatory conversion.

For more information about the senior credit facility and senior notes, see "Note 12—Long-Term Debt" to the Company's consolidated financial statements in Item 8 of this report. For information on the future maturities of the Company's long-term debt, see the table below under "Contractual Obligations and Off-Balance Sheet Arrangements."

Contractual Obligations and Off-Balance Sheet Arrangements

As of December 31, 2015, the Company had future contractual payment commitments under various agreements which are not recorded in the accompanying consolidated balance sheets. A summary of the Company's contractual obligations as of December 31, 2015 is provided in the following table (in thousands):

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | Less than 1 year | 1-3 years | 3-5 years | More than 5 years |
| | (In thousands) | | | | |
| Long-term debt obligations(1) | $5,579,384 | $316,805 | $633,610 | $2,257,110 | $2,371,859 |
| Transportation and throughput agreements | 64,068 | 14,082 | 28,032 | 10,866 | 11,088 |
| Third-party drilling rig agreements(2) | 2,457 | 2,457 | — | — | — |
| Asset retirement obligations | 103,578 | 8,399 | 7,029 | 3,138 | 85,012 |
| Operating leases and other(3) | 30,180 | 3,318 | 5,061 | 1,333 | 20,468 |
| Total | $5,779,667 | $345,061 | $673,732 | $2,272,447 | $2,488,427 |

(1) Includes interest on long-term debt and assumes debt principal amounts are outstanding until their latest contractual maturity, with no additional conversions of Convertible Senior Notes to common stock. As such, the outstanding liability balances as of December 31, 2015 for the long-term debt holder conversion feature of $29.4 million and the mandatory prepayment feature for the PGC Senior Secured Notes of $2.9 million are not included in the table above. See "Note 5—Fair Value Measurements" and "Note 13—Derivatives" for discussion of these additional obligations.

(2) Includes drilling contracts with third-party drilling rig operators at specified day or footage rates and termination fees associated with the Company's hydraulic fracturing services agreements. All of the Company's drilling rig contracts contain operator performance conditions that allow for pricing adjustments or early termination for operator nonperformance.

(3) Includes the Company's obligation for the employee and employer match contributions to the participants of its non-qualified deferred compensation plan for eligible highly compensated employees who elect to defer income exceeding the Internal Revenue Service annual limitations on qualified 401(k) retirement plans.

Drilling Carry Commitment. As of December 31, 2015, the Company had drilled 453 net wells under a drilling carry arrangement with Repsol and did not satisfy the total drilling commitment under the arrangement of 484 net wells in the area of mutual interest, within the required time period, which ended May 31, 2015. As a result, the Company will carry a portion of Repsol's drilling and completion costs up to approximately $31.0 million for wells drilled in the future in the related area of mutual interest. The Company incurred approximately $16.1 million in costs toward this obligation during the year ended December 31, 2015, and will continue to record such costs as they are incurred in future periods. See "Note 7—Property, Plant and Equipment" to the Company's consolidated financial statements in Item 8 of this report for additional discussion.

Treating Agreement. At December 31, 2015, the Company was party to a 30-year treating agreement with Occidental, under which it was required to deliver a total of approximately 3,200 Bcf of $CO_2$ by 2041. The Company was obligated to pay Occidental $0.25 per Mcf to the extent minimum annual $CO_2$ volumes were not met and had accrued approximately $109.9 million in such penalties through December 31, 2015. The Company was released from all past, current and future obligations related to this agreement in January 2016 as discussed under "Overview - Recent Events."

Valuation Allowance

In 2008 and 2009, the Company recorded full cost ceiling impairments totaling $3.5 billion on its oil and natural gas assets, resulting in the Company being in a net deferred tax asset position. Management considered all available evidence and concluded that it was more likely than not that some or all of the deferred tax assets would not be realized and established a valuation allowance against the Company’s net deferred tax asset in the period ending December 31, 2008. This valuation allowance has been maintained since 2008. See “Note 19—Income Taxes” to the Company’s consolidated financial statements in Item 8 of this report for more discussion on the establishment of the valuation allowance against the Company’s net deferred tax asset.

Management continues to closely monitor all available evidence in considering whether to maintain a valuation allowance on its net deferred tax asset. Factors considered are, but not limited to, the reversal periods of existing deferred tax liabilities and deferred tax assets, the historical earnings of the Company and the prospects of future earnings. For purposes of the valuation allowance analysis, “earnings” is defined as pre-tax earnings as adjusted for permanent tax adjustments.

The Company was in a cumulative negative earnings position until the 36-month period ended December 31, 2012 at which time it reached cumulative positive earnings. However, as a result of the Company closing the sale of the Permian Properties on February 26, 2013, the Company reverted back to a cumulative negative earnings position for the 36-month period ended March 31, 2013. See “Note 3—Acquisitions and Divestitures” to the Company’s consolidated financial statements in Item 8 of this report for discussion of the sale of the Permian Properties. Based on net book value, historical costs and proved reserves as of February 26, 2013, the Company recorded a loss on the sale of $398.9 million, which caused the Company to report a loss for the year ended December 31, 2013. The Company remains in a cumulative negative earnings position through the 36-month period ended December 31, 2015. One contributing factor to the cumulative negative earnings position for the 36-month period ended December 31, 2015 is the combined effect of the quarterly impairments of the Company’s assets totaling $4.8 billion. The resulting cumulative negative earnings are not a definitive factor in determining to maintain a valuation allowance as all available evidence should be considered, but it is a significant piece of negative evidence in management’s analysis.

The Company’s revenue, profitability and future growth are substantially dependent upon prevailing and future prices for oil and natural gas. The markets for these commodities continue to be volatile. Relatively modest drops in prices can significantly affect the Company’s financial results and impede its growth. Changes in oil and natural gas prices have a significant impact on the value of the Company’s reserves and on its cash flow. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas and a variety of additional factors that are beyond the Company’s control. Due to these factors, management has placed a lower weight on the prospects of future earnings in its overall analysis of the valuation allowance.

In determining whether to maintain the valuation allowance, management concluded that the objectively verifiable negative evidence of cumulative negative earnings for the 36-month period ending December 31, 2015, is difficult to overcome with any forms of positive evidence that may exist. Accordingly, management has not changed its judgment regarding the need for a full valuation allowance against its net deferred tax asset. The valuation allowance against the Company’s net deferred tax asset at December 31, 2015 was $1.9 billion. The Company’s net deferred tax asset position and corresponding valuation allowance significantly increased from December 31, 2014, primarily as a result of the effect of the aforementioned asset impairments recorded during the year ended December 31, 2015. The Company’s net deferred tax asset position and corresponding valuation allowance at December 31, 2014 was $0.6 billion.

Additionally, at December 31, 2015, the Company has valuation allowances totaling $92.0 million against specific deferred tax assets for which management has determined it is more likely than not that such deferred tax assets will not be realized for various reasons. The valuation allowance against these specific deferred tax assets would not be impacted by the foregoing discussion.

Critical Accounting Policies and Estimates

The discussion and analysis of the Company’s financial condition and results of operations are based upon the Company’s consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of the Company’s financial statements requires the Company to make assumptions and prepare estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The Company bases its estimates on historical experience and various other assumptions that the Company believes are reasonable; however, actual results may differ significantly. The Company’s critical accounting policies and additional information on significant estimates used by the Company are discussed below. See “Note 1—Summary of Significant Accounting Policies” to the Company’s consolidated financial statements in Item 8 of this report for additional discussion of the Company’s significant accounting policies.

Derivative Financial Instruments. To manage risks related to fluctuations in prices attributable to its expected oil and natural gas production, the Company enters into oil and natural gas derivative contracts. Entrance into such contracts is dependent upon prevailing or anticipated market conditions. The Company may also, from time to time, enter into interest rate swaps in order to manage risk associated with its exposure to variable interest rates and issue long-term debt that contains embedded derivatives.

The Company recognizes its derivative instruments as either assets or liabilities at fair value with changes in fair value recognized in earnings unless designated as a hedging instrument with specific hedge accounting criteria having been met. The Company has elected not to designate price risk management activities as accounting hedges under applicable accounting guidance, and, accordingly, accounts for its commodity derivative contracts at fair value with changes in fair value reported currently in earnings. Accordingly, the Company’s earnings may fluctuate significantly as a result of changes in fair value. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract. The related cash flow impact of the Company’s derivative activities are reflected as cash flows from operating activities unless the derivative contract contains a significant financing element, in which case, cash settlements are classified as cash flows from financing activities in the consolidated statements of cash flows.

Fair values of the substantial majority of the Company's commodity derivative financial instruments are determined primarily by using discounted cash flow calculations or option pricing models, and are based upon inputs that are either readily available in the public market, such as oil and natural gas futures prices, volatility factors, interest rates and discount rates, or can be corroborated from active markets. Estimates of future prices are based upon published forward commodity price curves for oil and natural gas instruments. Valuations also incorporate adjustments for the nonperformance risk of the Company or its counterparties, as applicable.

In August 2015, the Company issued its Convertible Senior Unsecured Notes, each of which contain a conversion option whereby the Convertible Senior Unsecured Notes holders have the option to convert the notes into shares of Company common stock. These conversion features have been identified as embedded derivatives that meet the criteria to be bifurcated from their host contracts, the Convertible Senior Unsecured Notes, and accounted for separately from those notes. The holder conversion features are recorded at fair value each reporting period, which was determined using a binomial lattice model based on certain assumptions including (i) the Company's stock price, (ii) risk-free rate, (iii) recovery rate, (iv) hazard rate and (v) expected volatility. The significant unobservable input used in the fair value measurement of the conversion features is the hazard rate, an estimate of default probability.

In October 2015, the Company issued the PGC Senior Secured Notes. The PGC Senior Secured Notes will mature on June 1, 2020; provided, however, that if on October 15, 2019, the aggregate outstanding principal amount of the Company's unsecured 8.75% Senior Notes due 2020 exceeds $100.0 million, the Senior Secured Notes will mature on October 16, 2019. The issuance of the PGC Senior Secured Notes at a substantial discount, as discussed in "Note 12—Long-Term Debt" and "Note 13—Derivatives" to the Company's consolidated financial statements included in Item 8 of this report, resulted in the treatment of the mandatory prepayment feature contained in those notes as an embedded derivative that meets the criteria to be bifurcated from its host contract, the PGC Senior Secured Notes, and is recorded at fair value each reporting period based upon values determined through the use of discounted cash flow models of the PGC Senior Secured Notes both (i) with the mandatory prepayment feature and (ii) excluding the mandatory prepayment feature.

Proved Reserves. Approximately 90.1% of the Company's reserves were estimated by independent petroleum engineers for the year ended December 31, 2015. Estimates of proved reserves are based on the quantities of oil, natural gas and NGLs that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond the Company's control. Estimating reserves is a complex process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner and relies on assumptions and subjective interpretations of available geologic, geophysical, engineering and production data, and the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, as a result of volatility and changing market conditions, commodity prices and future development costs will change from period to period, causing estimates of proved reserves to change, as well as causing estimates of future net revenues to change. For the years ended December 31, 2015, 2014 and 2013, the Company revised its proved reserves from prior years' reports by approximately (234.6) MMBoe, 20.3 MMBoe and (19.2) MMBoe, respectively, due to market prices during or at the end of the applicable period, production performance indicating more (or less) reserves in place, larger (or smaller) reservoir size than initially estimated or additional proved reserve bookings within the original field boundaries. Estimates of proved reserves are key components of the Company's most significant financial estimates used to determine depreciation and depletion on oil and natural gas properties and its full cost ceiling limitation. Future revisions to estimates of proved reserves may be material and could materially affect the Company's future depreciation and depletion expenses.

Method of Accounting for Oil and Natural Gas Properties. The Company's business is subject to accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full cost method. The Company uses the full cost method to account for its oil and natural gas properties. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Exploration and development costs include dry well costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil, natural gas and NGL reserves. Amortization of oil and natural gas properties is calculated using the unit-of-production method based on estimated proved oil, natural gas and NGL reserves. Sales and abandonments of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas and NGL reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion and impairment of oil and natural gas properties are generally calculated on a well by well, lease or field basis versus the aggregated "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method. As a result, the Company's financial statements will differ from companies that apply the successful efforts method since the Company will generally reflect a higher level of capitalized costs as well as a higher oil and natural gas depreciation and depletion rate, and the Company will not have exploration expenses that successful efforts companies frequently have.

Impairment of Oil and Natural Gas Properties. In accordance with full cost accounting rules, capitalized costs are subject to a limitation. The capitalized cost of oil and natural gas properties, net of accumulated depreciation, depletion and impairment, less related deferred income taxes, may not exceed an amount equal to the present value of future net revenues from proved oil, natural gas and NGL reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties, plus estimated salvage value, less related tax effects (the "ceiling limitation"). The Company calculates its full cost ceiling limitation using the 12-month average oil and natural gas prices for the most recent 12 months as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. If capitalized costs exceed the ceiling limitation, the excess must be charged to expense. Once incurred, a write-down cannot be reversed at a later date. The Company recorded full cost ceiling impairments of $4.5 billion and $164.8 million for the years ended December 31, 2015 and 2014. There were no full cost ceiling impairments recorded during the year ended December 31, 2013. See "Results by Segment" for additional discussion of full cost ceiling impairments.

Unproved Properties. The balance of unproved properties consists primarily of costs to acquire unproved acreage. These costs are initially excluded from the Company's amortization base until it is known whether proved reserves will or will not be assigned to the property. The Company assesses all properties, on an individual basis or as a group if properties are individually insignificant, classified as unproved on a quarterly basis for possible impairment or reduction in value. The assessment includes consideration of various factors, including, but not limited to, the following: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. The Company estimates that substantially all of its costs classified as unproved as of the balance sheet date will be evaluated and transferred within a 10-year period from the date of acquisition, contingent on the Company's capital expenditures and drilling program.

Property, Plant and Equipment, Net. Other capitalized costs, including drilling equipment, natural gas gathering and treating equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 10 to 39 years for buildings and 3 to 30 years for equipment. When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed and any resulting gain or loss is reflected in operations. Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying value of such asset or asset group may not be recoverable. Assets are considered to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset or asset group including disposal value, if any, is less than the carrying amount of the asset or asset group. If an asset or asset group is determined to be impaired, the impairment loss is measured as the amount by which the carrying amount of the asset or asset group exceeds its fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two as considered appropriate based on the circumstances. The Company may also determine fair value by using the present value of estimated future cash inflows and/or outflows, or third-party offers or prices of comparable assets with consideration of current market conditions to value its non-financial assets and liabilities when circumstances dictate determining fair value is necessary. Changes in such estimates could cause the Company to reduce the carrying value of property and equipment.

See “Note 8—Impairment” to the Company’s consolidated financial statements in Item 8 of this report for a discussion of the Company’s impairments.

Asset Retirement Obligations. Asset retirement obligations represent the estimate of fair value of the cost to plug, abandon and remediate the Company’s wells at the end of their productive lives, in accordance with applicable federal and state laws. The

Company estimates the fair value of an asset's retirement obligation in the period in which the liability is incurred (at the time the wells are drilled or acquired). Estimating future asset retirement obligations requires management to make estimates and judgments regarding timing, existence of a liability and what constitutes adequate restoration. The Company employs a present value technique to estimate the fair value of an asset retirement obligation, which reflects certain assumptions and requires significant judgment, including an inflation rate, its credit-adjusted, risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability based on third-party quotes and current actual costs. Inherent in the present value calculation rates are the timing of settlement and changes in the legal, regulatory, environmental and political environments, which are subject to change. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Revenue Recognition and Natural Gas Balancing. Oil, natural gas and NGL revenues are recorded when title of production sold passes to the customer, net of royalties, discounts and allowances, as applicable. Taxes assessed by governmental authorities on oil, natural gas and NGL sales are presented separately from such revenues and included in production tax expense in the consolidated statements of operations.

The Company accounts for natural gas production imbalances using the sales method, whereby it recognizes revenue on all natural gas sold to its customers notwithstanding the fact that its ownership may be less than 100% of the natural gas sold. Liabilities are recorded for imbalances greater than the Company's proportionate share of remaining estimated natural gas reserves.

The Company accounted for its construction contract, discussed in "Note 11—Construction Contract" to the Company's consolidated financial statements in Item 8 of this report, using the completed-contract method, under which contract revenues and costs are recognized when work under the contract is completed or substantially completed and assets have been transferred. In the interim, costs incurred on and billings related to contracts in process are accumulated on the consolidated balance sheets. Contract losses are recorded at the time it is determined that a loss will be incurred. Contract gains, if any, are recorded upon substantial completion of the construction project.
The Company recognizes revenues and expenses generated from daywork and footage drilling contracts as the services are performed as the Company does not bear the risk of completion of the well. The Company may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one location to another are recognized at the time mobilization services are performed.

In general, natural gas purchased and sold by the midstream business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Midstream services revenues are recognized upon delivery of natural gas to customers and/or when services are rendered, pricing is determined and collectability is reasonably assured. Revenues from third-party midstream services are presented on a gross basis, since the Company acts as a principal by taking ownership of the natural gas purchased and taking responsibility of fulfillment for natural gas volumes sold.

Income Taxes. Deferred income taxes are recorded for temporary differences between financial statement and income tax bases. Temporary differences are differences between the amounts of assets and liabilities reported for financial statement purposes and their tax basis. Deferred tax assets are recognized for temporary differences that will be deductible in future years' tax returns and for operating loss and tax credit carryforwards. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized. Deferred tax liabilities are recognized for temporary differences that will be taxable in future years' tax returns. As of December 31, 2015, the Company continued to have a full valuation allowance against its net deferred tax asset. The valuation allowance serves to reduce the tax benefits recognized from the net deferred tax asset to an amount that is more likely than not to be realized based on the weight of all available evidence.

Variable Interest Entities. An entity is referred to as a VIE if it possesses one of the following criteria: (i) it is thinly capitalized, (ii) the residual equity holders do not control the entity, (iii) the equity holders are shielded from economic losses, (iv) the equity holders do not participate fully in the entity's residual economics, or (v) the entity was established with non-substantive voting interests. The Company consolidates a VIE when it has determined it is the primary beneficiary, which requires significant judgment. The primary beneficiary of a VIE is that variable interest holder possessing a controlling financial interest through (i) its power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (ii) its obligation to absorb losses or its right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether the Company owns a variable interest in a VIE and the significance of the variable interest, the Company performs a qualitative analysis of the entity's design, organizational structure, primary decision makers and related financial agreements. In addition to the VIEs that the Company consolidates, during the years ended December 31, 2013 and 2014 and for a portion of 2015, the Company also held a variable interest in another VIE that is not consolidated as it was determined that the Company is not the primary beneficiary. The Company monitors both consolidated and unconsolidated VIEs to determine if any events have occurred that could cause the primary beneficiary to change. See “Note 4—Variable Interest Entities” to the Company’s consolidated financial statements in Item 8 of this report for a discussion of the Company’s VIEs.

New Accounting Pronouncements. For a discussion of recently adopted accounting standards and recent accounting standards not yet adopted, see “Note 1—Summary of Significant Accounting Policies” to the Company’s consolidated financial statements in Item 8 of this report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

General

This discussion provides information about the financial instruments the Company uses to manage commodity prices and interest rate volatility, including instruments used to manage commodity prices for production attributable to the Royalty Trusts. All contracts are settled in cash and do not require the actual delivery of a commodity at settlement.

Commodity Price Risk. The Company's most significant market risk relates to the prices it receives for oil, natural gas and NGLs. Due to the historical price volatility of these commodities, from time to time, depending upon management's view of opportunities under the then-prevailing current market conditions, the Company enters into commodity pricing derivative contracts for a portion of its anticipated production volumes for the purpose of reducing the variability of oil and natural gas prices it receives. The Company's senior credit facility limits its ability to enter into derivative transactions to 85% of expected production volumes from estimated proved reserves.

The Company uses, and may continue to use, a variety of commodity-based derivative contracts, including fixed price swaps, basis swaps and collars. At December 31, 2015, the Company's commodity derivative contracts consisted of fixed price swaps, basis swaps and collars, which are described below:

| | |
|---|---|
| Fixed price swaps | The Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume. |
| Basis swaps | The Company receives a payment from the counterparty if the settled price differential is greater than the stated terms of the contract and pays the counterparty if the settled price differential is less than the stated terms of the contract, which guarantees the Company a price differential for oil or natural gas from a specified delivery point. |
| Collars | Three-way collars have two fixed floor prices (a purchased put and a sold put) and a fixed ceiling price (call). The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The call establishes a maximum price (ceiling) the Company will receive for the volumes under the contract. |

The Company's oil fixed price swap transactions are settled based upon the average daily prices for the calendar month or quarter of the contract period. The Company's three-way oil collars are settled based upon the arithmetic average of NYMEX oil prices during the calculation period for the relevant contract. The Company's gas basis swap transactions are settled based upon the differential between the NYMEX Henry Hub price and Platts Inside FERC Panhandle Eastern Pipe Line price. Settlement for oil derivative contracts occurs in the succeeding month or quarter and natural gas derivative contracts are settled in the production month or quarter.

At December 31, 2015, the Company's open commodity derivative contracts consisted of the following:

Oil Price Swaps

| | Notional (MBbls) | Weighted Average Fixed Price |
|---|---|---|
| January 2016 - December 2016 | 1,464 | $88.36 |

Natural Gas Basis Swaps

| | Notional (MMcf) | Weighted Average Fixed Price |
|---|---|---|

| | | | |
|---|---|---|---|
| January 2016 - December 2016 | 10,980 | $(0.38 | ) |

Oil Collars - Three-way

| | Notional (MBbls) | Sold Put | Purchased Put | Sold Call |
|---|---|---|---|---|
| January 2016 - December 2016 | 2,556 | $83.14 | $90.00 | $100.85 |

Because the Company has not designated any of its derivative contracts as hedges for accounting purposes, changes in fair values of the Company's derivative contracts are recognized as gains and losses in current period earnings. As a result, the Company's current period earnings may be significantly affected by changes in the fair value of its commodity derivative contracts. Changes in fair value are principally measured based on future prices as of period-end compared to the contract price.

The Company recorded (gain) loss on commodity derivative contracts of $(73.1) million, $(334.0) million and $47.1 million for the years ended December 31, 2015, 2014 and 2013, respectively, as reflected in the accompanying consolidated statements of operations, which includes net cash (receipts) payments upon settlement of $(327.7) million, $32.3 million and $(0.8) million, respectively. Included in these net cash payments (receipts) for the years ended December 31, 2014 and 2013, are $69.6 million and $29.6 million of cash payments related to early settlements primarily as a result of the sale of the Gulf Properties in February 2014 and the Permian Properties in February 2013, respectively. For the year ended December 31, 2013, the gain on commodity derivative contracts is net of a non-cash loss of $117.1 million resulting from the amendment of certain 2012 derivative contracts to contracts maturing in 2014 and 2015.

See "Note 13—Derivatives" to the Company's consolidated financial statements in Item 8 of this report for additional information regarding the Company's commodity derivatives.

Credit Risk. All of the Company's derivative transactions have been carried out in the over-the-counter market. The use of derivative transactions in over-the-counter markets involves the risk that the counterparties may be unable to meet the financial terms of the transactions. The counterparties for all of the Company's derivative transactions have an "investment grade" credit rating. The Company monitors on an ongoing basis the credit ratings of its derivative counterparties and considers its counterparties' credit default risk ratings in determining the fair value of its derivative contracts. The Company's derivative contracts are with multiple counterparties to minimize its exposure to any individual counterparty.

A default by the Company under its senior credit facility constitutes a default under its derivative contracts with counterparties that are lenders under the senior credit facility. The Company does not require collateral or other security from counterparties to support derivative instruments. The Company has master netting agreements with all of its derivative contract counterparties, which allow the Company to net its derivative assets and liabilities with the same counterparty. As a result of the netting provisions, the Company's maximum amount of loss under derivative transactions due to credit risk is limited to the net amounts due from the counterparties under the derivative contracts. The Company's loss is further limited as any amounts due from a defaulting counterparty that is a lender under the senior credit facility can be offset against amounts owed, if any, to such counterparty under the Company's senior credit facility. As of December 31, 2015, the counterparties to the Company's open commodity derivative contracts consisted of eight financial institutions, three of which are also lenders under the Company's senior credit facility.

The Company's ability to fund its capital expenditure budget is partially dependent upon the availability of funds under its senior credit facility. In order to mitigate the credit risk associated with individual financial institutions committed to participate in the senior credit facility, the Company's bank group consists of 11 financial institutions with commitments ranging from 1.00% to 14.00% of the borrowing base as of December 31, 2015.

Interest Rate Risk. The Company is exposed to interest rate risk on its long-term fixed rate debt and will be exposed to variable interest rates if it draws on its senior credit facility. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes the Company to (i) changes in market interest rates reflected in the fair value of the debt and (ii) the risk that the Company may need to refinance maturing debt with new debt at a higher rate. Variable rate debt, where the interest rate fluctuates, exposes the Company to short-term changes in market interest rates as the Company's interest obligations on these instruments are periodically redetermined based on prevailing market interest rates, primarily the LIBOR and the federal funds rate. The Company had no outstanding variable rate debt as of December 31, 2015.

Prior to its maturity on April 1, 2013, the Company had a $350.0 million notional interest rate swap agreement, which effectively fixed the variable interest rate on the Senior Floating Rate Notes at an annual rate of 6.69% for periods prior to their repurchase and redemption in 2012. The Company recorded an insignificant loss on its interest rate swaps for the year ended December 31, 2013. The interest rate swap was not designated as a hedge.

## Item 8. Financial Statements and Supplementary Data

The Company’s consolidated financial statements required by this item are included in this report beginning on page F-1.

## Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures.

Under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer, the Company performed an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(b) and 15d-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the Company’s Chief Executive Officer and its Chief Financial Officer concluded that its disclosure controls and procedures were effective as of December 31, 2015 to provide reasonable assurance that the information required to be disclosed by the Company in its reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management’s Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm

The information required to be filed pursuant to this item is set forth under the captions “Management’s Report on Internal Control over Financial Reporting” and “Report of Independent Registered Public Accounting Firm” in Item 8 of this report.

Changes in Internal Control over Financial Reporting

There were no changes in the Company’s internal control over financial reporting during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Item 9B. Other Information

Not Applicable.

## PART III

### Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 29, 2016: "Director Biographical Information," "Executive Officers," "Compliance with Section 16(a) of the Exchange Act" and "Corporate Governance Matters."

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 29, 2016: "Director Compensation," "Outstanding Equity Awards" and "Executive Officers and Compensation."

## Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 29, 2016: "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management."

## Item 13. Certain Relationships and Related Transactions and Director Independence

The information required by this item is incorporated herein by reference to the following sections of the Company’s definitive proxy statement, which will be filed no later than April 29, 2016: “Related Party Transactions” and “Corporate Governance Matters.”

## Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the section captioned “Ratification of Selection of Independent Registered Public Accounting Firm” in the Company’s definitive proxy statement, which will be filed no later than April 29, 2016.

PART IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as a part of this report:
(1)Consolidated Financial Statements
Reference is made to the Index to Consolidated Financial Statements appearing on page F-1.
(2)Financial Statement Schedules
All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or notes thereto.
(3)Exhibits

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management’s Report on Internal Control over Financial Reporting

Management of SandRidge Energy, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Internal control over financial reporting is a process designed by, or under the supervision of, the Company’s Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company’s financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013) (the COSO criteria). Based on management’s assessment using the COSO criteria, management concluded the Company’s internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of the Company’s internal control over financial reporting as of December 31, 2015 has been audited by PricewaterhouseCoopers LLP an independent registered public accounting firm, as stated in its report which appears herein.

| | |
|---|---|
| /s/ JAMES D. BENNETT | /s/ JULIAN BOTT |
| James D. Bennett | Julian Bott |
| President and Chief Executive Officer | Executive Vice President and Chief Financial Officer |

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of SandRidge Energy, Inc.:

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

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the consolidated financial statements, the Company has engaged advisors to assist with a private restructuring or reorganization under Title 11 of the U.S. Bankruptcy Code in the foreseeable future, which raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

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

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

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
March 30, 2016

SandRidge Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

| | December 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (In thousands, except per share data) | |
| ASSETS | | |
| Current assets | | |
| Cash and cash equivalents | $435,588 | $181,253 |
| Accounts receivable, net | 127,387 | 330,077 |
| Derivative contracts | 84,349 | 291,414 |
| Prepaid expenses | 6,833 | 7,981 |
| Other current assets | 19,931 | 21,193 |
| Total current assets | 674,088 | 831,918 |
| Oil and natural gas properties, using full cost method of accounting | | |
| Proved (includes development and project costs excluded from amortization of $34.6 million and $53.6 million at December 31, 2015 and 2014, respectively) | 12,529,681 | 11,707,147 |
| Unproved | 363,149 | 290,596 |
| Less: accumulated depreciation, depletion and impairment | (11,149,888 ) | (6,359,149 ) |
| | 1,742,942 | 5,638,594 |
| Other property, plant and equipment, net | 491,760 | 576,463 |
| Derivative contracts | — | 47,003 |
| Other assets | 82,365 | 165,247 |
| Total assets | $2,991,155 | $7,259,225 |

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

SandRidge Energy, Inc., and Subsidiaries
Consolidated Balance Sheets—Continued

| | December 31, 2015 | 2014 |
|---|---|---|
| | (In thousands, except per share data) | |
| LIABILITIES AND STOCKHOLDERS' (DEFICIT) EQUITY | | |
| Current liabilities | | |
| Accounts payable and accrued expenses | $428,417 | $683,392 |
| Derivative contracts | 573 | — |
| Asset retirement obligations | 8,399 | — |
| Deferred tax liability | — | 95,843 |
| Other current liabilities | — | 5,216 |
| Total current liabilities | 437,389 | 784,451 |
| Long-term debt | 3,631,506 | 3,195,436 |
| Asset retirement obligations | 95,179 | 54,402 |
| Other long-term obligations | 14,814 | 15,116 |
| Total liabilities | 4,178,888 | 4,049,405 |
| Commitments and contingencies (Note 15) | | |
| Equity | | |
| SandRidge Energy, Inc. stockholders' (deficit) equity | | |
| Preferred stock, $0.001 par value, 50,000 shares authorized | | |
| 8.5% Convertible perpetual preferred stock; 2,650 shares issued and outstanding at December 31, 2015 and 2014; aggregate liquidation preference of $265,000 | 3 | 3 |
| 7.0% Convertible perpetual preferred stock; 2,770 shares issued and outstanding at December 31, 2015, aggregate liquidation preference of $277,000; 3,000 shares issued and outstanding at December 31, 2014, aggregate liquidation preference of $300,000 | 3 | 3 |
| Common stock, $0.001 par value; 1,800,000 shares authorized, 635,584 issued and 633,471 outstanding at December 31, 2015; 800,000 shares authorized, 485,932 issued and 484,819 outstanding at December 31, 2014 | 630 | 477 |
| Additional paid-in capital | 5,301,136 | 5,204,024 |
| Additional paid-in capital—stockholder receivable | (1,250) | (2,500) |
| Treasury stock, at cost | (5,742) | (6,980) |
| Accumulated deficit | (6,992,697) | (3,257,202) |
| Total SandRidge Energy, Inc. stockholders' (deficit) equity | (1,697,917) | 1,937,825 |
| Noncontrolling interest | 510,184 | 1,271,995 |
| Total stockholders' (deficit) equity | (1,187,733) | 3,209,820 |
| Total liabilities and stockholders' (deficit) equity | $2,991,155 | $7,259,225 |

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Operations

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In thousands, except per share amounts) | | |
| Revenues | | | |
| Oil, natural gas and NGL | $707,434 | $1,420,879 | $1,820,278 |
| Drilling and services | 22,124 | 76,088 | 66,586 |
| Midstream and marketing | 33,809 | 55,658 | 58,304 |
| Construction contract | — | — | 23,349 |
| Other | 5,342 | 6,133 | 14,871 |
| Total revenues | 768,709 | 1,558,758 | 1,983,388 |
| Expenses | | | |
| Production | 308,701 | 346,088 | 516,427 |
| Production taxes | 15,440 | 31,731 | 32,292 |
| Cost of sales | 24,394 | 56,155 | 57,118 |
| Midstream and marketing | 26,819 | 49,905 | 53,644 |
| Construction contract | — | — | 23,349 |
| Depreciation and depletion—oil and natural gas | 319,913 | 434,295 | 567,732 |
| Depreciation and amortization—other | 47,382 | 59,636 | 62,136 |
| Accretion of asset retirement obligations | 4,477 | 9,092 | 36,777 |
| Impairment | 4,534,689 | 192,768 | 26,280 |
| General and administrative | 137,715 | 113,991 | 207,920 |
| Employee termination benefits | 12,451 | 8,874 | 122,505 |
| (Gain) loss on derivative contracts | (73,061) | (334,011) | 47,123 |
| Loss on settlement of contract | 50,976 | — | — |
| Loss on sale of assets | 1,491 | 10 | 399,086 |
| Total expenses | 5,411,387 | 968,534 | 2,152,389 |
| (Loss) income from operations | (4,642,678) | 590,224 | (169,001) |
| Other (expense) income | | | |
| Interest expense | (321,421) | (244,109) | (270,234) |
| Gain (loss) on extinguishment of debt | 641,131 | — | (82,005) |
| Other income, net | 2,040 | 3,490 | 12,445 |
| Total other income (expense) | 321,750 | (240,619) | (339,794) |
| (Loss) income before income taxes | (4,320,928) | 349,605 | (508,795) |
| Income tax expense (benefit) | 123 | (2,293) | 5,684 |
| Net (loss) income | (4,321,051) | 351,898 | (514,479) |
| Less: net (loss) income attributable to noncontrolling interest | (623,506) | 98,613 | 39,410 |
| Net (loss) income attributable to SandRidge Energy, Inc. | (3,697,545) | 253,285 | (553,889) |
| Preferred stock dividends | 37,950 | 50,025 | 55,525 |
| (Loss applicable) income available to SandRidge Energy, Inc. common stockholders | $(3,735,495) | $203,260 | $(609,414) |
| (Loss) earnings per share | | | |
| Basic | $(7.16) | $0.42 | $(1.27) |
| Diluted | $(7.16) | $0.42 | $(1.27) |
| Weighted average number of common shares outstanding | | | |
| Basic | 521,936 | 479,644 | 481,148 |
| Diluted | 521,936 | 499,743 | 481,148 |

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Changes in Stockholders' Equity (Deficit)

| | Convertible Perpetual Preferred Stock | | Common Stock | | Additional Paid-In Capital | Treasury Stock | Accumulated Deficit | Non-controlling Interest | Total |
|---|---|---|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | | | | | |
| | (In thousands) | | | | | | | | |
| Balance at December 31, 2012 | 7,650 | $ 8 | 490,359 | $ 476 | $ 5,228,019 | $ (8,602) | $ (2,851,048) | $ 1,493,602 | $ 3,862,455 |
| Sale of royalty trust units | — | — | — | — | 7,289 | — | — | 21,696 | 28,985 |
| Distributions to noncontrolling interest owners | — | — | — | — | — | — | — | (206,470) | (206,470) |
| Contributions from noncontrolling interest owners | — | — | — | — | — | — | — | 1,579 | 1,579 |
| Purchase of treasury stock | — | — | — | — | — | (30,126) | — | — | (30,126) |
| Retirement of treasury stock | — | — | — | — | (30,126) | 30,126 | — | — | — |
| Stock purchases, net of distributions - retirement plans | — | — | (99) | — | (267) | (168) | — | — | (435) |
| Stock-based compensation | — | — | — | — | 88,397 | — | — | — | 88,397 |
| Stock-based compensation excess tax provision | — | — | — | — | (4) | — | — | — | (4) |
| Payment received on shareholder receivable | — | — | — | — | 1,250 | — | — | — | 1,250 |
| Issuance of restricted stock awards, net of cancellations | — | — | 30 | 7 | (7) | — | — | — | — |
| Net (loss) income | — | — | — | — | — | — | (553,889) | 39,410 | (514,479) |
| Convertible perpetual preferred stock dividends | — | — | — | — | — | — | (55,525) | — | (55,525) |
| Balance at December 31, 2013 | 7,650 | 8 | 490,290 | 483 | 5,294,551 | (8,770) | (3,460,462) | 1,349,817 | 3,175,627 |
| Sale of royalty trust units | — | — | — | — | 4,091 | — | — | 18,028 | 22,119 |
| Distributions to noncontrolling interest owners | — | — | — | — | — | — | — | (193,807) | (193,807) |
| | — | — | — | — | — | (6,373) | — | — | (6,373) |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Purchase of treasury stock | | | | | | | | | |
| Retirement of treasury stock | — | — | — | — | (6,373) | 6,373 | — | — | — |
| Stock distributions, net of purchases - retirement plans | — | — | 206 | — | (1,781) | 1,790 | — | — | 9 |
| Stock-based compensation | — | — | — | — | 23,665 | — | — | — | 23,665 |
| Stock-based compensation excess tax benefit | — | — | — | — | 14 | — | — | — | 14 |
| Payment received on shareholder receivable | — | — | — | — | 1,250 | — | — | — | 1,250 |
| Issuance of restricted stock awards, net of cancellations | — | — | 3,311 | 3 | (3) | — | — | — | — |
| Acquisition of ownership interest | — | — | — | — | (2,074) | — | — | (656) | (2,730) |
| Repurchase of common stock | — | — | (27,411) | (27) | (111,800) | — | — | — | (111,827) |
| Conversion of 6% preferred stock | (2,000) | (2) | 18,423 | 18 | (16) | — | — | — | — |
| Net income | — | — | — | — | — | — | 253,285 | 98,613 | 351,898 |
| Convertible perpetual preferred stock dividends | — | — | — | — | — | — | (50,025) | — | (50,025) |
| Balance at December 31, 2014 | 5,650 | 6 | 484,819 | 477 | 5,201,524 | (6,980) | (3,257,202) | 1,271,995 | 3,209,820 |
| Distributions to noncontrolling interest owners | — | — | — | — | — | — | — | (138,305) | (138,305) |
| Purchase of treasury stock | — | — | — | — | — | (2,428) | — | — | (2,428) |
| Retirement of treasury stock | — | — | — | — | (2,428) | 2,428 | — | — | — |
| Stock distributions, net of purchases - retirement plans | — | — | (1,000) | — | (916) | 1,238 | — | — | 322 |
| Stock-based compensation | — | — | — | — | 21,123 | — | — | — | 21,123 |
| Payment received on shareholder receivable | — | — | — | — | 1,250 | — | — | — | 1,250 |
| Issuance of restricted stock awards, net of cancellations | — | — | 1,514 | 5 | (5) | — | — | — | — |
| | — | — | 120,881 | | | | | | |

Common stock
issued for debt