SANDRIDGE ENERGY INC
Form 10-K
February 27, 2015

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, 2014
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 (State or other jurisdiction of incorporation or organization)	20-8084793 (I.R.S. Employer Identification No.)
123 Robert S. Kerr Avenue Oklahoma City, Oklahoma (Address of principal executive offices)	73102 (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 þ No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No 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 þ	Accelerated filer o
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, 2014 was approximately $3.4 billion based on the closing price as quoted on the New York Stock Exchange. As of February 20, 2015, there were 483,839,301 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company’s definitive proxy statement for the 2015 Annual Meeting of Stockholders are incorporated by reference in Part III.

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2014 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 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;
- economic viability of certain natural gas production in west Texas due to high CO_2 content;
- risks associated with obligations to deliver minimum volumes of natural gas and/or CO_2 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 oil and natural gas company with a principal focus on exploration and production activities in the Mid-Continent region of the United States. The Company owns and operates additional interests in west Texas and also owned interests in the Gulf of Mexico and Gulf Coast until February 2014, as discussed under "2014 Divestiture" below.

As of December 31, 2014, the Company had 4,486 gross (3,381.2 net) producing wells, a substantial portion of which it operates, and approximately 2,176,000 gross (1,558,000 net) total acres under lease. As of December 31, 2014, the Company had 35 rigs drilling in the Mid-Continent. Total estimated proved reserves as of December 31, 2014 were 515.9 MMBoe, of which approximately 65% 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, an electrical transmission system and a drilling and related oil field services business. As of December 31, 2014, the Company's drilling rig fleet consisted of 25 operational rigs. These complementary businesses provide the Company with operational flexibility and an advantageous cost structure by reducing its dependence on third parties for the services provided by these businesses.

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 region of the United States. In pursuit of its mission, the Company focuses on the following strategies:

- Concentrate in Core Operating Area. The Company's primary area of operation is the Mid-Continent area of Oklahoma and Kansas. By concentrating in this core area, the Company is able to (i) further build and utilize its technical expertise in order to interpret 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. 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 was experienced during the second half of 2014 and is currently being experienced, the Company preserves capital and liquidity by contracting its capital

expenditures budget and high-grading locations for development. During such times, the Company uses its decreased budgeted funds to capitalize 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 2015 capital expenditures budget is approximately $660 million, with approximately $610 million designated for exploration and production activities. This compares to 2014 total capital expenditures of approximately $1.6 billion and exploration and development capital expenditures of approximately $1.5 billion.

- 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 area. 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 completion designs, well site production facilities, utilization of pad drilling 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.
- Mitigate Commodity Price Risk. 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, as it has for 2015, 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.
- Asset Monetization. The Company periodically evaluates its properties to identify opportunities to monetize assets and may use proceeds realized from such transactions to fund the drilling and development of its core area, for general corporate purposes or to retire corporate debt.
- 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.
- Focus on Reservoirs with Known Hydrocarbon Production. The Company focuses its development efforts primarily in conventional, shallow, low-cost, permeable carbonate reservoirs with decades of production history. The nature of these reservoirs allows the Company to execute low-risk, repeatable drilling programs.
- Maintain Flexibility. The Company has multi-year inventories of both oil and natural gas drilling locations within its core operating area. Additionally, the Company maintains its own fleet of drilling rigs through its wholly owned drilling rig business. Maintaining inventories of both oil and natural gas drilling locations as well as its own drilling rigs 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, when appropriate, seeks to acquire them at a discount to other opportunities.

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.

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"), for $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 is using 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 plugging or abandonment costs as a result of this guarantee, which expired February 25, 2015.

BUSINESS SEGMENTS AND PRIMARY OPERATIONS

The Company operates in three business segments: exploration and production, drilling and oil field services and midstream services. Financial information regarding each segment is provided in Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Note 22—Business Segment Information” to the Company’s consolidated financial statements in Item 8 of this report. The information below includes the 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.

Exploration and Production

The Company explores for, develops and produces oil and natural gas, with a primary focus on increasing its reserves and production in the Mid-Continent. The Company operates substantially all of its wells in this area and also operates wells and owns leasehold positions in west Texas, and owned interests in the Gulf of Mexico and Gulf Coast until February 2014.

The following table presents information concerning the Company’s exploration and production activities by geographic area of operation as of December 31, 2014, 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	454.4	$ 5,071.0	79.3	15.7	2,077,875	1,486,504	$ 1,292.4
West Texas	61.5	445.4	10.5	16.0	98,286	71,490	191.2
Total	515.9	$ 5,516.4	89.8	15.7	2,176,161	1,557,994	$ 1,483.6

(1) For a reconciliation of PV-10 to Standardized Measure, see “—Proved Reserves.” The Company’s total Standardized Measure was $4.1 billion at December 31, 2014.
(2) Average daily net production for the month of December 2014.
(3) Estimated net proved reserves as of December 31, 2014 divided by production for the month of December 2014 annualized.
(4) Capital expenditures for the year ended December 31, 2014 on an accrual basis.

Properties

Mid-Continent

The Company held interests in approximately 2,078,000 gross (1,487,000 net) leasehold acres primarily in Oklahoma and Kansas at December 31, 2014. Associated proved reserves at December 31, 2014 totaled 454.4 MMBoe, 62% 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, 2014 included 2,437 gross (1,384.5 net) producing wells with an average working interest of 57%. The Company had 35 rigs operating in the Mid-Continent as of December 31, 2014, of which 31 were drilling horizontal wells and four were drilling saltwater disposal wells. The Company drilled a total of 439 horizontal wells, three vertical wells and 40 saltwater disposal wells in this area during 2014.

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 Morrow formation 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, 2014, the Company had approximately 1,988,000 gross (1,432,000 net) acres under lease in the Mississippian formation, of which approximately 48,000 gross (38,000 net) acres were included in the Mississippian Trust II area of mutual interest. The Company fulfilled its drilling obligation to the Mississippian Trust I in April 2013 after which the associated area of mutual interest terminated.

The Company has drilled approximately 1,545 wells in this formation as of December 31, 2014. From December 31, 2013 to December 31, 2014, the number of the Company's producing horizontal wells in the Mississippian formation increased from 1,167 to 1,555. Of the wells the Company drilled in the Mississippian formation during 2014, four wells are subject to the royalty interests of the Mississippian Trust II.

Other Formations. The Company drilled 35 wells in the Chester formation and eight wells in the Woodford formation in 2014 in order to determine commerciality and initiate development of these productive formations. Of the wells the Company drilled in the Chester formation during 2014, two wells are subject to the royalty interests of the Mississippian Trust II.

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. The Devonian-aged formation, which lies beneath the Mississippian formation and above various Lower Paleozoic formations and is stratigraphically equivalent to the Marcellus Shale in the Appalachian Basin and the Bakken Shale in the Williston Basin, 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 saltwater gathering and disposal system, constructed beginning in 2007, and electrical infrastructure, constructed beginning in 2009, assist in the economically efficient production of oil and natural gas in the Mid-Continent. The saltwater gathering and disposal system, which included more than 190 active wells and approximately 1,050 miles of gathering lines at December 31, 2014, reduces the overall cost of water disposal, which directly reduces production costs. The system has a current injection capacity of over 2.8 million barrels of water per day. The Company's electrical infrastructure, which consisted of approximately 1,000 miles of power lines and six substations at December 31, 2014, 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.

West Texas

The Company's west Texas oil and natural gas properties include properties in the West Texas Overthrust ("WTO") and the Permian Basin. The WTO is an area located in Pecos and Terrell Counties in west Texas and is associated with the Marathon-Ouachita fold and thrust belt that extends east-northeast across the United States into the Appalachian Mountain Region. The Permian Basin extends throughout southwestern Texas and southeastern New Mexico and is one of the largest, most active and longest-producing oil basins in the United States. In February 2013, the Company sold all of its oil and natural gas properties in the Permian Basin, other than those assets attributable to the Permian Trust's area of mutual interest.

The Company held interests in approximately 98,000 gross (71,000 net) leasehold acres in west Texas at December 31, 2014. Associated proved reserves at December 31, 2014 were 61.5 MMBoe, 92% of which were proved developed reserves. The Company's interests in west Texas as of December 31, 2014 included 2,049 gross (1,996.7 net) producing wells with an average working interest of 97%. The Company had no rigs operating in west Texas as of December 31, 2014. The Company drilled 187 wells in this area during 2014, of which 183 were drilled within the Permian Trust's area of mutual interest and subject to the Permian Trust's royalty interest. The Company fulfilled its drilling obligation to the Permian Trust in November 2014 after which the associated area of mutual interest terminated.

During 2014, low natural gas prices continued to limit development activity in the WTO, primarily a natural gas-producing region. Due to the sensitivity of drilling activity to market prices for natural gas, drilling activity in the WTO will likely remain very limited if natural gas prices remain low. Pursuant to a 30-year treating agreement with Occidental Petroleum Corporation ("Occidental"), the Company delivers natural gas produced in the WTO to Occidental's CO_2 treatment plant in Pecos County, Texas (the "Century Plant"), and Occidental removes CO_2 from natural gas volumes delivered by the Company. The Company retains all methane gas after treatment. Under the agreement, the Company is required to deliver a total of approximately 3,200 Bcf of CO_2 during the agreement period. The Company is obligated to pay Occidental $0.25 per Mcf to the extent minimum annual CO_2 volume requirements are not met and $0.70 per Mcf to the extent the total contract delivery requirement is not met by the end of the contract term. See further discussion of the CO_2 treating agreement in "Liquidity and Capital Resources - Contractual Obligations and Off-Balance Sheet Arrangements" included in Item 7 of this report.

Proved Reserves

Preparation of Reserve 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. 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 29 years of estimating and evaluating reserve information. In addition, SandRidge's Senior Vice President—Corporate Reservoir Engineering has 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 15 full-time employees, comprised of five degreed engineers and 10 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 Executive 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 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. In the event the quarterly updated reserves estimates are disclosed, the aforementioned review process is evidenced by signatures from the Senior Vice President—Corporate Reservoir Engineering and the Chief Financial Officer.

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 table below shows the percentage of the Company's total proved reserves for which each of the independent petroleum consultants prepared reports of estimated proved reserves of oil, natural gas and NGLs for the years shown.

	December 31,					
	2014		2013		2012	
Cawley, Gillespie & Associates, Inc.	82.4	%	64.6	%	—	%
Netherland, Sewell & Associates, Inc.	3.7	%	21.5	%	72.7	%
Lee Keeling and Associates, Inc.	—	%	—	%	24.9	%
Total	86.1	%	86.1	%	97.6	%

The remaining 13.9%, 13.9% and 2.4% of the Company's estimated proved reserves as of December 31, 2014, 2013 and 2012, 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, 2014 are filed with this report as Exhibits 99.1 and 99.2. The geographic location of the Company's estimated proved reserves prepared by each of the independent petroleum consultants as of December 31, 2014 is presented below.

	Geographic Locations—by Area by State
Cawley, Gillespie & Associates, Inc.	Mid-Continent - KS, OK
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 27 years of practical experience in petroleum engineering and more than 25 years of experience estimating and evaluating reserve information;
- a registered professional engineer in the state of Texas; and
- a Bachelor of Science Degree in Petroleum Engineering.

Netherland, Sewell & Associates, Inc.
- practicing consulting petroleum engineering since 2013 and over 14 years of prior industry experience;
- licensed professional engineers in the state of Texas; and
- Bachelor of Science Degree in Chemical Engineering

Lee Keeling and Associates, Inc.
- more than 58 years of practical experience in petroleum engineering and more than 54 years estimating and evaluating reserve information;
- a registered professional engineer in the state of Oklahoma; and
- a Bachelor of Science Degree in Petroleum 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.

Reporting of Natural Gas Liquids

Natural gas liquids, or NGLs, are produced as a result of the processing of a portion of the Company's natural gas production stream. At December 31, 2014, NGLs comprised approximately 18% 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, 2014, 2013 and 2012, 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, 2014, 2013 and 2012, using first-day-of-the-month prices for each month. Such prices are not reflective of actual prices at December 31, 2014 or current prices. See further discussion of prices in "Risk Factors" included in Item 1A of this report. At December 31, 2014, the Company estimated that approximately 100% of its current proved undeveloped reserves will be developed by the end of 2017. See "Critical Accounting Policies and Estimates" in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates.

	December 31,		
	2014	2013	2012
Estimated Proved Reserves(1)			
Developed			
Oil (MMBbls)	79.0	83.9	136.6
NGL (MMBbls)	56.8	35.8	33.8
Natural gas (Bcf)	1,203.4	951.6	896.7
Total proved developed (MMBoe)	336.4	278.3	319.9
Undeveloped			
Oil (MMBbls)	47.0	58.7	125.4
NGL (MMBbls)	35.0	23.3	34.2
Natural gas (Bcf)	584.8	438.8	518.3
Total proved undeveloped (MMBoe)	179.5	155.1	246.0
Total Proved			
Oil (MMBbls)	126.0	142.6	262.0
NGL (MMBbls)	91.8	59.1	68.0
Natural gas (Bcf)	1,788.2	1,390.4	1,415.0
Total proved (MMBoe)(2)	515.9	433.4	565.9
PV-10 (in millions)(3)	$5,516.4	$5,191.6	$7,488.4
Standardized Measure of Discounted Net Cash Flows (in millions)(2)(4)	$4,087.8	$4,017.6	$5,840.4

(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, 2014	$91.48	$4.35	$91.65	$32.79	$3.61
December 31, 2013	$93.42	$3.67	$95.67	$31.40	$3.65
December 31, 2012	$91.21	$2.76	$91.65	$32.64	$2.29

(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 and 2012, 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, 2014	27.6	$643.3
December 31, 2013	29.9	$781.6
December 31, 2012	38.2	$952.7

See “Note 24—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, 2014, 2013 and 2012. 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 an arbitrary 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,		
	2014	2013	2012
	(In millions)		
Standardized Measure of Discounted Net Cash Flows	$4,087.8	$4,017.6	$5,840.4
Present value of future income tax discounted at 10%	1,428.6	1,174.0	1,648.0
PV-10	$5,516.4	$5,191.6	$7,488.4

(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 235.8 MMBoe at December 31, 2012 to 302.3 MMBoe at December 31, 2013 and to 454.4 MMBoe at December 31, 2014, comprising a significant portion of the additions to the Company’s proved reserves for the three-year period. The reserves attributable to producing wells and the continuity of the formation over the development area further support proved undeveloped classification of locations within close proximity to the producing wells. Data from both the Company and operators of offset wells with which it has exchanged technical data demonstrate a consistency in this formation and the fluids in place over an area much larger than the development area. In addition, direct measurement from other producing wells was also used to confirm consistency in reservoir properties such as porosity, thickness and stratigraphic conformity. These wells all encountered proven reserves in the Mississippian formation. The proved undeveloped locations within the development area are generally parallel offsets to the horizontal wells drilled and producing to date.

Proved Reserves - West Texas. 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. In 2013, the Company sold the Permian Properties as discussed in “2013 Divestiture” above. As a result, proved reserves in the Permian Basin decreased by 198.9 MMBoe from

December 31, 2012 to December 31, 2013. The Permian Basin provides access to shallow, permeable carbonate reservoirs with decades of production history and predictable production profiles.

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

	Year Ended December 31,		
	2014	2013	2012
Reserves converted from proved undeveloped to proved developed (MMBoe)	31.4	44.6	42.6
Drilling capital expended to convert proved undeveloped reserves to proved developed reserves (in millions)	$343.6	$437.6	$718.2

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.

The Company recognized a net addition to oil, natural gas and NGL reserves associated with proved undeveloped properties, excluding asset sales and purchases of reserves, for the year ended December 31, 2012. Additional reserves attributable to extensions and discoveries, primarily in the Mid-Continent area and Permian Basin area in west Texas, were a result of successful drilling. These additions were partially offset by downward revisions of reserve quantities primarily from the Piñon Field in the WTO as a result of lower natural gas index prices, and, to a lesser extent, downward revisions of reserve quantities due to well performance in the Mid-Continent during 2012. The 12-month average natural gas index price of $4.12 per Mcf for 2011 decreased to $2.76 per Mcf for 2012.

For additional information regarding changes in the Company’s proved reserves during the three years ended December 31, 2014, 2013 and 2012 see “Note 24—Supplemental Information on Oil and Natural Gas Producing Activities” to the Company’s consolidated financial statements in Item 8 of this report.

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 and Fuhrman-Mascho fields each contained more than 15% of the Company’s total proved reserves at December 31, 2014, 2013 or 2012.

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)
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
Year Ended December 31, 2012				
Mississippi Lime Horizontal	4,536	100	33,034	10,142
Fuhrman-Mascho	4,104	561	1,768	4,960

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, 2014 included 1,779 gross (1,067.8 net) producing wells and a 60% average working interest in the producing area.

Fuhrman-Mascho Field. The Fuhrman-Mascho Field is located near the center of the Central Basin Platform in the Permian Basin and produces from the Grayburg-San Andres formation from average depths of approximately 4,500 to 5,000 feet. The Company sold properties located in the Fuhrman-Mascho field and elsewhere in the Permian Basin in February 2013 as discussed in “2013 Divestiture” above.

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,		
	2014	2013	2012
Production Data			
Oil (MBbls)	10,876	14,279	15,868
NGL (MBbls)	3,794	2,291	2,094
Natural gas (MMcf)	85,697	103,233	93,549
Total volumes (MBoe)	28,953	33,776	33,553
Average daily total volumes (MBoe/d)	79.3	92.5	91.7
Average Prices(1)			
Oil (per Bbl)	$89.86	$97.58	$91.79
NGL (per Bbl)	$33.41	$35.16	$33.10
Natural gas (per Mcf)	$3.70	$3.36	$2.49
Total (per Boe)	$49.08	$53.89	$52.43

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

	Year Ended December 31,		
	2014	2013	2012
Expenses per Boe			
Lease operating expenses			
Transportation	$1.23	$1.29	$0.89
Processing, treating and gathering(1)	1.16	1.05	1.18
Other lease operating expenses(2)	9.27	12.60	11.56
Total lease operating expenses	$11.66	$14.94	$13.63
Production taxes(3)	$1.10	$0.96	$1.41
Ad valorem taxes	$0.29	$0.35	$0.59

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

(2) The years ended December 31, 2014, 2013 and 2012 include $33.9 million, $32.7 million and $8.5 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, 2014. 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	1,922	1,158.3	515	226.2	2,437	1,384.5
West Texas	1,268	1,246.4	781	750.3	2,049	1,996.7
Total	3,190	2,404.7	1,296	976.5	4,486	3,381.2

Developed and Undeveloped Acreage

The following table sets forth information regarding the Company's developed and undeveloped acreage at December 31, 2014:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Area				
Mid-Continent	634,701	416,010	1,443,174	1,070,494
West Texas	56,120	49,871	42,166	21,619
Total	690,821	465,881	1,485,340	1,092,113

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, 2014, 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, 2015	390,675	280,021
December 31, 2016	576,271	423,579
December 31, 2017	341,661	264,902
December 31, 2018 and later	13,735	11,528
Other(1)	162,998	112,083
Total	1,485,340	1,092,113

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

Included in the acreage set to expire during the 12 months ending December 31, 2015, as presented in the table above, are approximately 382,025 gross (277,537 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 2015 and expects to exercise such options or hold by production a substantial portion of such acreage based on current drilling and operational plans.

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, 2014, the Company had 32 gross (21.6 net) operated wells drilling, completing or awaiting completion.

	2014				2013				2012			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Completed Wells												
Development												
Productive	626	97.5 %	482.3	97.4 %	607	98.1 %	482.3	98.1 %	1,054	99.8 %	930.9	99.8 %
Dry	16	2.5 %	13.0	2.6 %	12	1.9 %	9.5	1.9 %	2	0.2 %	1.7	0.2 %
Total	642	100.0 %	495.3	100.0 %	619	100.0 %	491.8	100.0 %	1,056	100.0 %	932.6	100.0 %
Exploratory												
Productive	6	60.0 %	4.6	60.5 %	44	80.0 %	31.0	79.3 %	32	97.0 %	24.3	96.0 %
Dry	4	40.0 %	3.0	39.5 %	11	20.0 %	8.1	20.7 %	1	3.0 %	1.0	4.0 %
Total	10	100.0 %	7.6	100.0 %	55	100.0 %	39.1	100.0 %	33	100.0 %	25.3	100.0 %
Total												
Productive	632	96.9 %	486.9	96.8 %	651	96.6 %	513.3	96.7 %	1,086	99.7 %	955.2	99.7 %
Dry	20	3.1 %	16.0	3.2 %	23	3.4 %	17.6	3.3 %	3	0.3 %	2.7	0.3 %
Total	652	100.0 %	502.9	100.0 %	674	100.0 %	530.9	100.0 %	1,089	100.0 %	957.9	100.0 %

The following table sets forth information with respect to all rigs operating on the Company's acreage as of December 31, 2014.

	Owned	Third-Party	Total
Mid-Continent	10	25	35

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 2014. See "Note 22—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 and the demand for such commodity 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.

Drilling and Oil Field Services

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 oil field services subsidiary. The Company believes that drilling with its own rigs allows it to control costs and maintain operating flexibility. The Company's rig fleet is designed to drill in its specific areas of operation and has an average of over 800 horsepower and an average depth capacity of greater than 10,500 feet. As of December 31, 2014, the Company's drilling rig fleet consisted of 25 operational rigs with 10 of these rigs working on Company-owned properties in the Mid-Continent. Additionally, the Company's oil field services business provides pulling units, trucking, rental tools, location and road construction and roustabout services that, together with its drilling services, complement its exploration and production business.

Demand for the Company's drilling and oilfield services in the Permian region declined significantly in the latter half of 2014 as a result of the Company's fulfillment of its drilling obligation with the Permian Trust and the downward trend in oil prices that began during that period. At December 31, 2014, the Company determined the future use of its drilling and oilfield services assets in this region was limited and recorded an impairment of $24.3 million on these assets. In the first quarter of 2015, the Company decided to discontinue all remaining drilling and oil field services operations in the Permian region. During 2014 and 2013, the Company also recorded impairments of approximately $3.1 million and $11.1 million, respectively, on certain drilling assets identified for sale in order to adjust their carrying values to fair value.

The Company obtains its drilling contracts through either competitive bidding or direct negotiations with customers. The Company’s drilling contracts generally provide for compensation on a daywork or footage basis. Contract terms offered by the Company generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, the anticipated duration of the work to be performed and prevailing market rates.

Customers

During 2014, the Company performed approximately 61% of its drilling and oil field services in support of its exploration and production business. For the years ended December 31, 2014, 2013 and 2012, the Company generated revenues of $76.1 million, $66.6 million and $116.6 million, respectively, for drilling and oil field services performed for third parties.

Capital Expenditures

The Company's capital expenditures for 2014 related to its drilling and oil field services were $18.4 million. The Company has budgeted approximately $5.0 million in capital expenditures in 2015 for its drilling and oil field services segment.

Midstream Services

The Company's midstream services segment primarily provides gathering, compression and treating services of natural gas in west Texas and coordinates the delivery of electricity to the Company's exploration and production operations in the Mid-Continent area. The Company's midstream operations and assets serve its exploration and production business as well as other oil and natural gas companies as described below.

Marketing

Through Integra Energy, L.L.C., a wholly owned subsidiary, the Company buys and sells natural gas from wells it operates and wells operated by third parties within its west Texas area of operations. The Company generally buys and sells natural gas on simultaneous contracts using a portfolio of baseload and spot sales agreements. Identical volumes are bought and sold on monthly and daily contracts using a combination of published pricing indices to eliminate price exposure.

The Company conducts thorough credit checks of all potential purchasers and minimizes its exposure by contracting with multiple parties each month. The Company does not engage in any hedging activities with respect to these contracts. The Company manages several interruptible natural gas transportation agreements in order to take advantage of price differentials or to secure available markets when necessary. The Company currently has 50,000 MMBtu per day of firm transportation service subscribed on the Mid-Continent Express Pipeline through July 2019. See "Note 15—Commitments and Contingencies" to the Company's consolidated financial statements in Item 8 of this report for additional information on the contractual fees associated with the firm transportation service.

Mid-Continent

The Company has constructed an electrical transmission system in the Mid-Continent area to coordinate the delivery of electricity to the Company's operations in the area. See discussion of the electrical transmission system under "—Properties—Mid-Continent."

West Texas Gas Treating Plants

The Company owns the Pike's Peak gas treating plant and the Grey Ranch gas treating plant, both located in Pecos County, Texas. During 2013 and 2012, the Company recorded impairments of $9.9 million and $79.3 million, respectively, on these plants and the Company's CO_2 compression facilities due to the anticipation that their future use would be limited. There was no impairment recorded for these assets during the year ended December 31, 2014. Throughout 2012, the Company diverted its high CO_2 natural gas production from its gas treating plants to the Century Plant while it was being tested and commissioned. Upon substantial completion of the Century Plant in late 2012, natural gas volumes delivered by the Company for processing at the Century Plant became subject to the terms of the 30-year treating agreement with Occidental, which contains minimum CO_2 delivery requirements. All natural gas produced in the WTO during 2014 and 2013 was processed at the Century Plant. See further discussion of the treating agreement under "—Properties—West Texas" above and in "Management's Discussion and Analysis—Liquidity and Capital Resources—Contractual Obligations and Off-Balance Sheet Arrangements." Due to the continued decline in natural gas production in the WTO resulting from the lack of drilling activity in the area, volumes currently produced in the WTO and delivered to the Century Plant for processing are not sufficient to use all of the available treating capacity at the Century Plant. Due to the sensitivity of drilling activity to market prices for natural gas, drilling activity in the WTO will likely remain very limited if natural gas prices remain low.

The Company is party to a gas gathering agreement and an operations and maintenance agreement with Piñon Gathering Company, LLC ("PGC") related to the Company's properties located in the Piñon Field in west Texas. Under the gas gathering agreement, the Company has dedicated the Piñon Field acreage for priority gathering services for a period of 20 years and will pay a fee for such services. See "Note 15—Commitments and Contingencies" to the Company's consolidated financial statements in Item 8 of this report for additional information on the contractual fees associated with this gas gathering agreement.

Customers

During 2014, the Company performed approximately 61% of its midstream services in support of its exploration and production business. For the years ended December 31, 2014, 2013 and 2012, the Company generated revenues of $55.4 million, $56.1 million and $38.8 million, respectively, from midstream services performed for third parties.

Capital Expenditures

The growth of the Company's midstream assets is driven by its oil and natural gas exploration and production operations. Historically, pipeline and facility expansions are made when warranted by an increase in production or the development of additional acreage. During 2014, the Company spent $44.6 million in capital expenditures primarily to install electrical and compression infrastructure. The Company has budgeted approximately $30.0 million in 2015 capital expenditures for its midstream services segment.

COMPETITION

The Company believes that its leasehold acreage position, drilling and oil field services businesses, midstream assets, geographic concentration of operations, vertical integration 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, and the Company faces competition in each of its business segments.

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.

With respect to the Company's drilling business, the Company believes the type, age and condition of its drilling rigs, the quality of its crews and the responsiveness of its management generally enable the Company to compete effectively. However, to the extent the Company drills for third parties, it encounters substantial competition from other drilling contractors. The Company's primary market area is highly competitive. The drilling contracts for which the Company competes are usually awarded on the basis of competitive bids. The Company may, based on the economic environment at the time, determine that market conditions and profit margins are such that contract drilling for third parties is not a beneficial use of its resources.

The Company believes pricing and rig availability are the primary factors its potential customers consider in determining which drilling contractor to select. While the Company must be competitive in its pricing, its competitive strategy generally emphasizes the quality of its equipment and the experience of its rig crews to differentiate it from its competitors. This strategy is less effective when demand for drilling services is weak or there is an oversupply of rigs. These conditions usually result in increased price competition, which makes it more difficult for the Company to compete on the basis of factors other than price. Many of the Company’s competitors have greater financial, technical and other resources than the Company does enabling them to better withstand industry downturns and retain skilled rig personnel.

The Company believes its geographic concentration of operations enables it to compete effectively in its midstream business. Most of the Company’s midstream assets are integrated with its production. However, with respect to third-party natural gas and acquisitions, the Company competes with companies that have greater financial and personnel resources than it does. These companies may have a greater ability to price their services below the Company’s prices for similar services.

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 and comprehensive federal, state, tribal, regional and local laws and regulations that are intended to protect the environment. These laws and regulations may, among other things, require permits to conduct drilling, water withdrawal and waste disposal operations; govern the amounts and types 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 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 monetary penalties, the imposition of remedial obligations and the issuance of orders enjoining operations in affected areas. Pursuant to such laws, regulations and permits, the Company may be subject to operational restrictions and has made, and will continue to make, capital and other compliance expenditures.

Increasingly, restrictions and limitations are being placed on activities that may affect the environment. Any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly construction, drilling, water management, completion, waste handling, storage, transport, disposal, or remediation requirements or emission or discharge limits could have a material adverse effect on the Company. Moreover, accidental releases or 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 following is a summary of the more significant existing environmental and employee, health and safety laws and regulations 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 Resource Conservation and Recovery Act, as amended ("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 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. Under CERCLA, these "responsible persons" may be subject to strict, joint and several liability for the costs of cleaning up sites where the hazardous substances were released, including 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 U.S. Environmental Protection Agency ("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 exempt from regulation as hazardous wastes under RCRA. However, it is possible that these wastes could be classified as hazardous wastes in the future. In September 2010, the Natural Resources Defense Council filed a petition with the EPA requesting reconsideration of the exemption for exploration, development and production wastes under RCRA. To date, the EPA has not taken any formal action in response to the petition. Any change in the exemption 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 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. Obtaining permits has the potential to delay the development of oil and natural gas projects. The Company may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues as a result of such requirements. 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.

In August 2012, the EPA issued final regulations that established new air emission controls for oil and natural gas production and natural gas processing, including, among other things, new source performance standards for volatile organic compounds that would apply to newly hydraulically fractured wells, existing wells that are re-fractured, compressors, pneumatic controllers, storage vessels and natural gas processing plants placed in service after August 2011. On December 19, 2014, the EPA finalized updates and clarifications to its 2012 New Source Performance Standards for the oil and natural gas industry. The updates provide additional detail on requirements of handling of gas and liquids during well completion operations, clarify requirements for storage tanks, define low-pressure wells, clarify certain requirements for leak detection at natural gas processing plants and update requirements for reciprocating compressors. The EPA has also implemented an engine emission testing program to ensure certain categories of engines, depending on the date manufactured, meet the EPA emission standards. The Company currently has an engine testing plan in place.

Water Discharges

The Federal Clean Water Act, as amended (the “CWA”), including 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 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 are exempt from the provisions of the CWA. Nevertheless, the Company employs certain controls whenever construction activities commence to prevent the discharge of sediment into nearby water bodies. Finally, the CWA requires measures to be taken to prevent the accidental discharge of oil into waters of the United States from onshore production facilities. These measures 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 SPCC plans for properties that are subject to the CWA.

The CWA further imposes certain duties and liabilities on “responsible parties” related to the prevention of oil spills and damages resulting from such spills in, or threatening, United States waters, including the Outer Continental Shelf or adjoining shorelines. A liable responsible party includes the owner or operator of an onshore facility, vessel, or pipeline that is a source, or a potential threat, of an oil discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. The CWA assigns joint and several strict liability, without regard to fault, to each liable party 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 the CWA, 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.

Climate Change

In December 2009, the EPA 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. These findings allow the EPA to adopt and implement regulations that restrict emissions of GHGs under existing provisions of the Clean Air Act. Accordingly, the EPA has adopted rules that require a reduction in emissions of GHGs from motor vehicles and also trigger Clean Air Act construction and operating permit review for GHG emissions from certain stationary sources. The EPA’s endangerment finding and GHG rules were upheld by the United States Court of Appeals for the D.C. Circuit in a June 2012 decision, and a petition for review of the case by the entire D.C. Circuit was denied in December 2012. While somewhat limiting the EPA's regulatory reach, the Supreme Court in 2014 upheld the finding that the EPA reasonably interpreted the Clean Air Act to require sources that would need permits based on their emission of conventional pollutants to comply with “best available control technology” for greenhouse gases.

The EPA has also 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 believes it has complied with all applicable reporting requirements to date. 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.

In addition, Congress has considered legislation to reduce emissions of GHGs and more than one-half of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the adoption of a climate change action plan, completion of GHG emission inventories and/or regional GHG cap and trade programs. 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.

The United States is also engaged in negotiations, through the United Nations, to develop a successor international agreement to the Kyoto Protocol of the United Nations Framework Convention on Climate Change. These efforts are scheduled to continue, with an aim to accomplishing an agreed upon approach in Paris in December 2015. While the contours of any agreement are still subject to negotiation, the existence of commitments by the United States could increase the domestic effort at reducing GHG emissions, including through further regulation of emissions from oil and gas production or from enhanced efficiency efforts designed to limit demand for oil and gas product, all potentially materially affecting the company's financial position.

Endangered or Threatened Species

The Endangered Species Act (the "ESA") restricts activities that may affect endangered or threatened species or their habitats. 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 of the underlying properties 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 on September 9, 2011, the U.S. Fish and Wildlife Service (the "FWS") is required to consider listing more than 250 species as endangered under the ESA. Under the September 9, 2011 settlement, the federal agency is required to make a determination on listing of the species as endangered or threatened over the six-year period ending with the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted, such as the March 2014 designation of the lesser prairie chicken as a threatened species, 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.

On March 27, 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. Listing of the lesser prairie chicken as threatened imposes restrictions on disturbances to critical habitat by landowners and drilling companies that would harass, harm or otherwise result in a "taking" of this species. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies (the "WAFWA") pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. The listing of the lesser prairie chicken as a threatened species and entry into certain range-wide conservation planning agreements, such as those developed by WAFWA, could result in increased costs to the Company from species protection measures, as well as delays and restrictions on their drilling program activities.

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, as amended (“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, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices, including the use of diesel, kerosene and similar compounds in the fracturing fluid. In August 2012, the EPA issued final Clean Air Act regulations governing performance standards, including for the capture of air emissions released during hydraulic fracturing.

Among other actions, EPA in a recent Fact Sheet announced plans to expand its New Source Performance Standards for the oil and gas sector to reduce methane emissions and to further restrict emissions of volatile organic compounds. EPA indicates that it intends to issue a proposed rule in late summer 2015 and a final rule in 2016. EPA also announced plans to provide state air permitting agencies with special "guidelines" for controlling volatile organic compound emissions from existing oil and gas sources located in ozone nonattainment areas and the Ozone Transport Region.

Also, federal legislation previously was introduced, but not enacted, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In May 2012, the Bureau of Land Management within the U.S. Department of the Interior issued a proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands, but in January 2013 it announced that it would be submitting a revised rule proposal. That revised proposed rule was published for public comment in May 2013. The final rule would provide for disclosure to the public of chemicals used in hydraulic fracturing on public land and Indian land, strengthen regulations related to well-bore integrity, and address issues related to recovered water. The Department of the Interior is now analyzing the comments and is expected to promulgate a final rule sometime in 2015. In addition, BLM has announced that it will update standards to reduce wasteful venting, flaring and leaks of natural gas, which is primarily methane, from oil and gas wells. These standards, to be proposed in the spring of 2015, will address both new and existing oil and gas wells on public lands, in operational aspects not covered by EPA's proposed rule.

Certain states in which the Company operates, including Texas, Kansas and Oklahoma, and municipalities therein, have adopted, or are considering adopting, regulations that have imposed, or that could impose, more stringent permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations. For example, in February 2012, the Railroad Commission of Texas implemented the Fracturing Disclosure Rule requiring public disclosure of all the chemicals in fluids used in the hydraulic fracturing process. Local ordinances or other regulations may regulate or prohibit the performance of well drilling in general and hydraulic fracturing in particular, including imposing certain setback requirements. 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, a number of federal entities are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. In April 2012, President Obama issued an executive order that established a working group for the purpose of coordinating policy, information sharing and planning across federal agencies and offices regarding “unconventional natural gas production,” including hydraulic fracturing. In December 2012, the EPA issued an initial progress report on a study begun in 2011 of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft final report expected to be issued for peer review and comment during 2015.

The EPA is developing a proposed rule to amend the Effluent Limitations Guidelines and Standards for the Oil and Gas Extraction Category. The proposed rule is scheduled for publication in early 2015. The proposal would address discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works. The EPA continues to collect and analyze information and will examine a variety of options for these discharges. The EPA has also published an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act. The notice will begin the public participation process and seek public comment on the types of chemical information that could be reported and disclosed under the Toxic Substances Control Act and the approaches to obtain this information on chemicals and mixtures used in hydraulic fracturing activities, including non-regulatory approaches.

Additionally, a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices, and certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and the U.S. Energy Information Administration to provide a better understanding of that agency’s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. The studies and initiatives described above, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

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 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 Advance Notice of Proposed Rulemaking proposes enhanced tank car standards, a classification and testing program for mined gases and liquids and new operational requirements for high-hazard flammable trains that include braking controls and speed restrictions. Specifically, within two years, it proposes the phase out of the use of older DOT 111 tank cars for the shipment of packing group I flammable liquids, including most Bakken crude oil, unless the tank cars are retrofitted to comply with new tank car design standards. An accompanying Advance Notice of Proposed Rulemaking seeks further information on expanding comprehensive oil spill response planning requirements for shipments of flammable materials.

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 (“ACOE”) 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 Safe Drinking Water Act, or 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, 2014, the Company had 1,878 full-time employees, including 164 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of the Company's 1,878 employees, 661 were located at the Company's headquarters in Oklahoma City, Oklahoma at December 31, 2014, and the remaining employees work in the Company's various field offices and drilling sites.

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.

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 2014 of $91.48/Bbl for oil and $4.35/Mcf for natural gas, the ratio of economic value of oil to gas was approximately 21 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.

High CO_2 gas. Natural gas that contains more than 10% CO_2 by volume.

Imbricate stacking. A geological formation characterized by multiple layers lying lapped over each other.

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.

(i) 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. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

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.

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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 oil field.

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 oil field 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.

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Item 1A. Risk Factors

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 and natural gas leaks, pipeline ruptures and discharges of toxic gases or well fluids;
- 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. 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 1, 2010 through December 31, 2014, the highest monthly NYMEX settled price was $113.93 per Bbl and the lowest was $53.27 per Bbl. For natural gas, from January 1, 2010 through December 31, 2014, the highest monthly NYMEX settled price was $6.06 per MMBtu and the lowest was $2.04 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 in early 2015, to as low as $44.45 per Bbl in January 2015. 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 $164.8 million for the year ended December 31, 2014, and had cumulative full cost ceiling impairment charges of $3.7 billion and $3.5 billion at December 31, 2014 and 2013, respectively. The Company had no full cost ceiling impairments during the years ended December 31, 2013 or 2012. 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 Company's 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 could reduce the amount available to be borrowed by the Company under its senior credit facility.

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, 2014, the Company's total indebtedness was $3.2 billion and the Company had preferred stock outstanding with an aggregate liquidation preference of $565.0 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, such as its obligations to drill wells for the Mississippian Trust II, 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. Oil prices fell sharply in the latter half of 2014 and remain at very low levels. Accordingly, if the Company had prepared its December 31, 2014 reserve reports based on the last month-end posted index prices at that time (which were $49.75 and $3.00 at December 31, 2014) instead of the 12-month average index prices (which were $91.48 and $4.35), the PV-10 value of its estimated proved reserves would necessarily have been lower. 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 2014, the Company completed a total of 652 gross wells, of which 20 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 secured revolving credit facility ("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, 2014, 35% 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, 2014, approximately 88% of the Company's proved reserves and approximately 80.9% 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 $621.1 million, $868.6 million and $783.2 million, for the years ended December 31, 2014, 2013 and 2012, respectively. The Company expects to finance its future capital expenditures with cash on hand, cash flow from operations, asset sales and available borrowing capacity under its senior credit facility. 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 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. On February 23, 2015, the Company and its lenders amended the credit agreement to address the risk that, in light of depressed oil and natural gas prices, the Company would breach certain financial covenants in 2015. 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

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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.

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 drilling and services revenues depend on the needs of other companies in the oil and natural gas industry.
Companies to which the Company provides drilling and related 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 drilling and related 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 drilling and services segment by negatively affecting:

- revenues, cash flow and profitability;
- the Company's ability to retain skilled rig personnel whom it would need in the event of an upturn in the demand for drilling and related services; and
- the fair value of the Company's rig fleet.

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.

Low levels of natural gas production in the WTO, due to declines in production from existing wells and, depressed commodity prices, currently adversely affect, and could in the future adversely affect, revenues and cash flow from the Company's midstream services segment, and are likely to adversely affect the Company's ability to satisfy certain contractual obligations.

The Company has entered into long-term gas gathering agreements with each of PGC and Occidental. These agreements require the Company to annually deliver certain minimum volumes of natural gas to PGC through June 30, 2029 and CO_2 to Occidental through December 31, 2041 and to compensate PGC and Occidental to the extent it does not satisfy the contractual delivery requirements. Decreased production in the WTO, where the applicable natural gas assets are located, has resulted in, and is likely to continue to result in, a decline in the volume of natural gas and CO_2 delivered to PGC and Occidental, respectively, and to its own pipelines and facilities for gathering, transporting and treating. The Company has no control over many factors affecting production activity in the WTO, including prevailing and projected natural gas prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital. As a result of these factors, the Company has not produced and delivered, and may continue to not produce and deliver, sufficient quantities of natural gas or CO_2 to meet its contractual delivery obligations to PGC and Occidental. The Company is required to compensate PGC and Occidental for shortfalls in its contractual delivery obligations. The Company accrued $33.9 million for its 2014 shortfalls under its contract with Occidental and expects to accrue between approximately $31.0 million and $38.0 million during the year ending December 31, 2015 for amounts related to the Company's anticipated shortfall in meeting its 2015 annual delivery obligations to Occidental based on current projected natural gas production levels. In future years, amounts payable to PGC and/or Occidental for such shortfalls could be material. In addition, if the Company fails to connect new wells to its gathering systems, the amount of natural gas it gathers, transports and treats will decline substantially over time and could, upon exhaustion of the current wells, cause the Company to abandon its gathering systems and, possibly cease gathering, transporting and treating operations.

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 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 and comprehensive federal, state and local laws and regulations governing 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 a permit before conducting drilling; water withdrawal or waste disposal 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 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 administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of the Company’s operations.

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 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 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 in more stringent or costly construction, drilling, water management, completion, waste handling, storage, transport, disposal or cleanup 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. 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.

Recent listing of the lesser prairie chicken as a threatened species under the federal Endangered Species Act may serve to delay or limit the operations of the Company.

The Endangered Species Act, or ESA, and analogous state laws regulate activities that could have an adverse effect on threatened and endangered species. Exploratory and producing 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. On March 27, 2014, the Fish and Wildlife Service, or 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. Listing of the lesser prairie chicken as threatened imposes restrictions on disturbances to critical habitat by landowners and drilling companies that would harass, harm or otherwise result in a “taking” of this species. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies, ("WAFWA"), pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. The listing of the lesser prairie chicken as a threatened species, and entry into certain range-wide conservation planning agreements, could result in increased costs to the Company from species protection measures, as well as delays and restrictions on their drilling program activities.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations, such as shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is typically regulated by state oil and gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose by early 2015 effluent limit guidelines that waste water from shale gas extraction operations must meet before going to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in May 2013, the Bureau of Land Management within the U.S. Department of the Interior issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the Department of the Interior is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule sometime in 2015. Also, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing, including the underground disposal of fluids or propping agents associated with such fracturing activities and to require disclosure of the chemicals used in the fracturing process.

Certain states in which the Company operates, including Texas, Kansas and Oklahoma, and municipalities have adopted, or are considering adopting, regulations that have imposed, or that could impose, more stringent permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations. For example, in February 2012, the Railroad Commission of Texas implemented the Fracturing Disclosure Rule, requiring public disclosure of all the chemicals in fluids used in the hydraulic fracturing process. Local ordinances or other regulations may regulate or prohibit the performance of well drilling in general and hydraulic fracturing in particular. If new laws or regulations that significantly restrict or regulate hydraulic fracturing are adopted at either the state or the 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, 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, a number of federal entities are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. In April 2012, President Obama issued an executive order that established a working group for the purpose of coordinating policy, information sharing, and planning among federal agencies and offices regarding “unconventional natural gas production,” including hydraulic fracturing. In December 2012, the EPA issued an initial progress report on a study begun in 2011 of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft final report expected to be issued for peer review and comment during 2015. The studies and initiatives described above, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

Legislation or regulatory initiatives intended to address seismic activity 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 gas economically.

The Company disposes of large volumes of saltwater produced alongside oil and natural gas in connection with its drilling and production operations, pursuant to permits issued to the Company 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.

There exists a growing concern that the injection of saltwater into belowground disposal wells triggers seismic activity in certain areas, including Oklahoma, Kansas and Texas, where the Company operates. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in the permitting of saltwater disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, on October 28, 2014, the Texas Railroad Commission, or TRC, published a new rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

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. Similarly, in September 2014, the governor of Oklahoma announced the creation of a Coordinating Council on Seismic Activity, which is intended to help researchers, policymakers, regulators and oil and natural gas industry study seismicity in the state. The Utility and Environment Committee of the Oklahoma House of Representatives also held an interim study to examine what, if any, correlations exist between wastewater disposal wells and seismic activity in the state. Although the committee did not recommend any policies, procedures or legislative items on the basis of the interim study, this does not foreclose the possibility of new law or regulations in the future. Finally, the Oklahoma Corporation Commission, or OCC, has exercised its regulatory authority to request that saltwater disposal wells be shut-in pending further review on two occasions, one of which was with respect to one of the Company's disposal wells. There is no assurance that these wells will be allowed to resume disposal at any time, and the OCC may take similar action with respect to additional wells in the future.

The adoption and implementation of any new laws or regulations 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, which could require the Company to shut in a substantial number of its oil and natural gas wells or otherwise have a material adverse effect on the Company's ability to produce oil and gas economically and, accordingly, could materially and adversely affect the Company's business, financial condition and results of operations.

Climate change laws and regulations restricting emissions of "greenhouse gases" 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.
In December 2009, the EPA 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. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the Clean Air Act. Accordingly, the EPA has adopted rules that require a reduction in emissions of GHGs from motor vehicles and also trigger Clean Air Act construction and operating permit review for GHG emissions from certain stationary sources. The EPA's endangerment finding and GHG rules were upheld by the United States Court of Appeals for the D.C. Circuit in a June 2012 decision, and a petition for review of the case by the entire D.C. Circuit was denied in December 2012.

The EPA also 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 believes it has complied with all applicable reporting requirements to date. 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.

In addition, Congress has considered legislation to reduce emissions of GHGs and more than half of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the adoption of a climate change action plan, completion of GHG emission inventories and/or regional GHG cap and trade programs. 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.

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 did not maintain effective internal control over financial reporting as of December 31, 2014, as further described in Item 9A—Controls and Procedures. 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 2016, 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 ("IT") 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 IT 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. It is anticipated that the plaintiffs will seek rehearing by the Court of Appeals and possibly petition 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.

On August 4, 2011, Patriot Exploration, LLC, Jonathan Feldman, Redwing Drilling Partners, Mapleleaf Drilling Partners, Avalanche Drilling Partners, Penguin Drilling Partners and Gramax Insurance Company Ltd. filed a lawsuit against the Company, SandRidge Exploration and Production, LLC (“SandRidge E&P”) and certain current and former directors and senior executive officers of the Company (collectively, the “defendants”) in the U.S. District Court for the District of Connecticut. On October 28, 2011, the plaintiffs filed an amended complaint alleging substantially the same allegations as those contained in the original complaint. The plaintiffs allege that the defendants made false and misleading statements to U.S. Drilling Capital Management LLC and to the plaintiffs prior to the entry into a participation agreement among Patriot Exploration, LLC, U.S. Drilling Capital Management LLC and SandRidge E&P, which provided for the investment by the plaintiffs in certain of SandRidge E&P’s oil and natural gas properties. To date, the plaintiffs have invested approximately $16.0 million under the participation agreement. The plaintiffs seek compensatory and punitive damages and rescission of the participation agreement. On November 28, 2011, the defendants filed a motion to dismiss the amended complaint. On June 29, 2013, the court granted in part and denied in part the defendants’ motion. The Company and the other defendants intend to defend this lawsuit vigorously and believe the plaintiffs’ claims are without merit. 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.

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
- 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 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 and how those claims should be asserted on the Company’s behalf.

The Company and the individual defendants in the Hefner and Romano actions (the “State Shareholder Derivative Litigation”) moved to stay each of the actions in favor of the Federal Shareholder Derivative Litigation, in order to avoid duplicative proceedings, and also requested, in the alternative, the dismissal of the State Shareholder Derivative Litigation.

On June 19, 2013, the court stayed the Hefner action until at least November 29, 2013. The court subsequently lifted its stay for purposes of hearing and deciding the defendants’ respective motions to dismiss. On September 18, 2013, the court denied the defendants’ motions to dismiss. The parties have agreed to stay this action pending the review and investigation by the SLC of the claims alleged by the plaintiffs in the Federal Shareholder Derivative Litigation and in this action, and to determine whether and how those claims should be asserted on the Company's behalf.

On May 8, 2013, the court stayed the Romano action pending further order of the court. On October 31, 2013, the plaintiff filed a motion to lift the stay, which was denied by the court on February 7, 2014. On October 29, 2014, the court granted plaintiff's application to dismiss the action without prejudice.

Because the Federal Shareholder Derivative Litigation and the State Shareholder Derivative Litigation are in the early stages, an estimate of reasonably possible losses associated with each of them, 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 these actions.

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 SandRidge Energy, Inc. 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 (together with the Mississippian Trust I, the "Mississippian Trusts") 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. The defendants have filed respective motions to dismiss the consolidated amended complaint, which are pending before the court. 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 the 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 E&P, 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. All of these motions are pending before the court.

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. 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.

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 Company is cooperating with the investigation.

On November 10, 2014, a class action complaint was filed in the U. S. District Court for the Western District of Oklahoma against certain current and former directors and officers of the Company in the case styled Steve Surbaugh vs. SandRidge Energy, Inc., Tom L. Ward, James D. Bennett, Eddie M. LeBlanc, and Randall D. Cooley. The complaint asserts a federal securities class action on behalf of a putative class consisting of all persons other than defendants who purchased SandRidge securities between March 1, 2013, through November 4, 2014, seeking to recover damages allegedly caused by the defendants' violations of federal securities laws under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, and Rule 10b-5 promulgated thereunder. The complaint alleges that, throughout the class period, the defendants made materially false and misleading statements regarding SandRidge’s business, operations and future prospects because such statements failed to properly account for the penalties SandRidge accrued under its treating agreement with Occidental Petroleum Corporation and, as a result, SandRidge’s financial statements were materially false and misleading during the class period. An estimate of reasonably possible losses associated with this action cannot be made at this time. The Company has not established any reserves relating to this action.

On November 11, 2014, a class action complaint was filed in the U. S. District Court for the Western District of Oklahoma against certain current and former directors and officers of the Company in the case styled Steven T. Dakil vs. SandRidge Energy, Inc., Tom L. Ward, James D. Bennett, and Eddie M. LeBlanc. The complaint asserts a federal securities class action on behalf of a putative class consisting of all persons other than defendants who purchased or otherwise acquired SandRidge securities between February 28, 2013, and November 3, 2014, seeking to recover damages allegedly caused by the defendants’ violations of federal securities laws under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, and Rule 10b-5 promulgated thereunder. The complaint alleges that, throughout the class period, defendants made materially false and misleading statements regarding SandRidge’s business, operational and compliance policies. Specifically, plaintiff alleges that defendants made false and/or misleading statements and/or failed to disclose that: (i) SandRidge was improperly accounting for penalties owed to Occidental Petroleum Corp. under a treating agreement on an annual basis when it was required to do so on a quarterly basis; (ii) SandRidge's quarterly and annual financial and operating results for the periods ending December 31, 2012 through June 30, 2014, were overstated and required restatement; (iii) defendant Ward engaged in improper related party transactions; (iv) SandRidge lacked proper internal controls over financial reporting; and (v) as a result of the foregoing, SandRidge’s financial statements were materially false and misleading during the class period. An estimate of reasonably possible losses associated with this action cannot be made at this time. The Company has not established any reserves relating to this action.

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

The Company’s common stock is 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
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
2013		
Fourth Quarter	$6.96	$5.21
Third Quarter	$5.99	$4.72
Second Quarter	$5.60	$4.52
First Quarter	$7.47	$5.05

On February 20, 2015, there were 278 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, 2010 through December 31, 2014. 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, 2010.

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, 2014.

	Total Number of Shares Purchased(1)(2)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program(2)	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program (In millions)
Period				
October 1, 2014 — October 31, 2014	23,919,390	$3.92	23,911,000	$88.7
November 1, 2014 — November 30, 2014	7,488	$3.90	N/A	N/A
December 1, 2014 — December 31, 2014	14,642	$1.93	N/A	N/A
Total	23,941,520		23,911,000	

(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. For the three-month period ended December 31, 2014, 30,520 shares were reacquired at a weighted average price per share of $3.02 to satisfy tax obligations for vested employee stock awards.

(2) Includes shares of common stock repurchased pursuant to a program approved by the Company’s Board of Directors and announced on September 4, 2014. Under the terms of the program, the Company may repurchase up to $200.0 million of the Company’s common stock. There is no fixed termination date for this repurchase program, which may be suspended or discontinued at any time.

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 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, the acquisition of oil and natural gas properties in the Gulf of Mexico from Dynamic Offshore Resources LLC (the "Dynamic Acquisition") in April 2012 and the acquisition of Arena Resources, Inc. in July 2010. 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,				
	2014	2013	2012	2011	2010
	(In thousands, except per share data)				
Statement of Operations Data					
Revenues	$1,558,758	$1,983,388	$1,934,642	$1,415,213	$931,736
Expenses					
Production	346,088	516,427	477,154	322,877	237,863
Production taxes	31,731	32,292	47,210	46,069	29,170
Cost of sales	56,155	57,118	68,227	65,654	22,368
Midstream and marketing	49,905	53,644	39,669	66,007	90,149
Construction contract	—	23,349	—	—	—
Depreciation and depletion—oil and natural gas	434,295	567,732	568,029	317,246	265,914
Depreciation and amortization—other	59,636	62,136	60,805	53,630	50,776
Accretion of asset retirement obligations	9,092	36,777	28,996	9,368	9,421
Impairment	192,768	26,280	316,004	2,825	—
General and administrative(1)	122,865	330,425	241,682	148,643	179,565
(Gain) loss on derivative contracts	(334,011)	47,123	(241,419)	(44,075)	50,872
Loss (gain) on sale of assets	10	399,086	3,089	(2,044)	2,424
Total expenses	968,534	2,152,389	1,609,446	986,200	938,522
Income (loss) from operations	590,224	(169,001)	325,196	429,013	(6,786)
Other income (expense)					
Interest expense	(244,109)	(270,234)	(303,349)	(237,332)	(247,442)
Bargain purchase gain	—	—	122,696	—	—
Loss on extinguishment of debt	—	(82,005)	(3,075)	(38,232)	—
Other income, net	3,490	12,445	4,741	3,122	2,558
Total other expense	(240,619)	(339,794)	(178,987)	(272,442)	(244,884)
Income (loss) before income taxes	349,605	(508,795)	146,209	156,571	(251,670)
Income tax (benefit) expense	(2,293)	5,684	(100,362)	(5,817)	(446,680)
Net income (loss)	351,898	(514,479)	246,571	162,388	195,010
Less: net income attributable to noncontrolling interest	98,613	39,410	105,000	54,323	4,445
Net income (loss) attributable to SandRidge Energy, Inc.	253,285	(553,889)	141,571	108,065	190,565
Preferred stock dividends	50,025	55,525	55,525	55,583	37,442
Income available (loss applicable) to SandRidge Energy, Inc. common stockholders	$203,260	$(609,414)	$86,046	$52,482	$153,123

Earnings (loss) per share					
Basic	$0.42	$(1.27)	$0.19	$0.13	$0.52
Diluted	$0.42	$(1.27)	$0.19	$0.13	$0.52
Weighted average number of common shares outstanding					
Basic	479,644	481,148	453,595	398,851	291,869
Diluted	499,743	481,148	456,015	406,645	315,349

(1) Includes employee termination benefits.

	As of December 31,				
	2014	2013	2012	2011	2010
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$181,253	$814,663	$309,766	$207,681	$5,863
Property, plant and equipment, net	$6,215,057	$6,307,675	$8,479,977	$5,389,424	$4,733,865
Total assets	$7,259,225	$7,684,795	$9,790,731	$6,219,609	$5,231,448
Total debt	$3,195,436	$3,194,907	$4,301,083	$2,814,176	$2,909,086
Total equity	$3,209,820	$3,175,627	$3,862,455	$2,548,950	$1,547,483
Total liabilities and equity	$7,259,225	$7,684,795	$9,790,731	$6,219,609	$5,231,448

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 oil and natural gas company with a principal focus on exploration and production activities in the Mid-Continent region of the United States. The Company's mission is to become a high-return, growth-oriented resource conversion company in the Mid-Continent where it has determined it has competitive advantages, such as an industry leading cost structure, subsurface knowledge, existing infrastructure and broader infrastructure capabilities and size and scale. As discussed further below under "Divestitures" the Company sold the majority of its Permian Basin assets in 2013 and its Gulf Properties in 2014 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.

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, an electrical transmission system and a drilling and related oil field services business.

Divestitures

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 the Company making 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 years ended December 31, 2013 and 2012:

	Year Ended December 31,	
	2013(1)	2012
Production (MBoe)	1,148	8,667
Revenues (in thousands)	$68,027	$566,075
Direct operating expenses (in thousands)	$17,453	$130,337

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

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 is using 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. Without regard to same-counterparty netting, these derivative contracts were in a liability position at December 31, 2013 of $72.4 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, 2013 and 2012 were as follows:

	Year Ended December 31,		
	2014(1)	2013	2012
Production (MBoe)	1,321	10,082	8,110
Revenues (in thousands)	$90,920	$627,236	$449,420
Expenses (in thousands)	$63,674	$491,991	$360,209

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

2014 Operational Highlights

Operational highlights for 2014 include the following:

- Drilled 442 wells, excluding salt water disposal wells, in the Mid-Continent area. Mid-Continent properties contributed approximately 23.4 MMBoe, or 80.9%, of the Company's total production in 2014 compared to approximately 17.8 MMBoe, or 52.7%, in 2013.
- Gulf Properties divested in February 2014, as discussed below, contributed production of approximately 1.3 MMBoe, or 4.6% of the Company's total production in 2014 compared to approximately 10.1 MMBoe, or 29.8% of total production in 2013.
- Total production for 2014 was comprised of approximately 37.6% oil, 49.3% natural gas and 13.1% NGLs compared to 42.3% oil, 50.9% natural gas and 6.8% NGLs in 2013.

Outlook

Oil prices fell sharply in the latter half of 2014 and remain at very low levels. Accordingly, the Company's 2015 capital expenditures budget is approximately $700.0 million, with approximately $650.0 million designated for exploration and production activities. These amounts reflect a decrease from 2014 capital expenditures of 56% and 57%, respectively. In 2015, the Company plans to capitalize on its in place saltwater gathering and disposal and electrical systems by focusing its drilling efforts on locations that can most effectively make use of this existing infrastructure, while also continuing its multilateral program within a high-graded inventory of locations including newly-targeted formations such as the Chester and Woodford formations. To that end, the Company intends to invest only in projects that are expected to have a positive return at recent strip pricing. Additionally, the Company expects costs industry-wide to align more closely with the current commodity pricing environment throughout 2015, resulting in improved and more certain returns.

In light of current commodity prices and the Company’s leverage, the Company is analyzing a variety of transactions and mechanisms designed to reduce debt and/or increase net income, including opportunistic acquisitions, the monetization of non-income producing assets, the retirement or purchase of outstanding debt securities through cash purchases and/or exchanges for other Company securities in open market purchases, privately negotiated transactions or otherwise. Such transactions, if any, will depend on prevailing market conditions, the Company’s liquidity requirements, contractual restrictions and other factors.

Results by Segment

The Company operates in three reportable business segments: exploration and production, drilling and oil field services and midstream services. These segments represent the Company’s three main business units, each offering 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 oil field services segment is engaged in the contract drilling of oil and natural gas wells and provides various oil field 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, 2014, 2013 and 2012 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 during the years ended December 31, 2014, 2013, 2012, 2011 and 2010 are presented in the table below:

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Oil (per Bbl)	$92.91	$98.05	$94.15	$95.11	$79.61
Natural gas (per Mcf)	$4.26	$3.73	$2.83	$4.03	$4.38

In order to reduce the Company’s exposure to price fluctuations, the Company enters 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, 2014, 2013 and 2012.

	Year Ended December 31,		
	2014	2013	2012
Results (in thousands)			
Revenues			
Oil	$977,269	$1,393,360	$1,456,590
NGL	126,759	80,555	69,306
Natural gas	316,851	346,363	233,386
Other	2,194	14,202	15,939
Inter-segment revenue	(173)	(320)	(403)
Total revenues	1,422,900	1,834,160	1,774,818
Operating expenses			
Production	348,387	519,546	480,001
Production taxes	31,731	32,292	47,210
Depreciation and depletion—oil and natural gas	434,295	567,732	568,029
Accretion of asset retirement obligations	9,092	36,777	28,996
Impairment	164,779	—	235,396
(Gain) loss on derivative contracts	(334,011)	47,123	(241,419)
(Gain) loss on sale of assets	(39)	398,543	3,499
Other operating expenses	54,950	169,638	134,962
Total operating expenses	709,184	1,771,651	1,256,674
Income from operations	$713,716	$62,509	$518,144
Production data			
Oil (MBbls)	10,876	14,279	15,868
NGL (MBbls)	3,794	2,291	2,094
Natural gas (MMcf)	85,697	103,233	93,549
Total volumes (MBoe)	28,953	33,776	33,553
Average daily total volumes (MBoe/d)	79.3	92.5	91.7
Average prices—as reported(1)			
Oil (per Bbl)	$89.86	$97.58	$91.79
NGL (per Bbl)	$33.41	$35.16	$33.10
Natural gas (per Mcf)	$3.70	$3.36	$2.49
Total (per Boe)	$49.08	$53.89	$52.43
Average prices—including impact of derivative contract settlements(2)			
Oil (per Bbl)	$94.18	$98.90	$97.53
NGL (per Bbl)	$33.41	$35.16	$33.10
Natural gas (per Mcf)	$3.58	$3.46	$2.46
Total (per Boe)	$50.36	$54.79	$55.04

(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.

The table below presents production by area of operation for the years ended December 31, 2014, 2013 and 2012 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, the majority of which were purchased during the second quarter of 2012 in the Dynamic Acquisition and (iii) the sale of the Permian Properties in February 2013.

	Year Ended December 31,					
	2014		2013		2012	
	Production (MBoe)	% of Total Production	Production (MBoe)	% of Total Production	Production (MBoe)	% of Total Production
Mid-Continent	23,423	80.9 %	17,783	52.7 %	11,039	32.9 %
Gulf of Mexico / Gulf Coast	1,321	4.6 %	10,082	29.8 %	8,110	24.2 %
Permian Basin	2,076	7.2 %	3,366	10.0 %	10,963	32.6 %
Other - west Texas	2,133	7.3 %	2,545	7.5 %	3,441	10.3 %
Total	28,953	100.0 %	33,776	100.0 %	33,553	100.0 %

Revenues

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 a decrease in production due to 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.

Exploration and production segment revenues from oil, natural gas and NGL sales increased by a combined $61.0 million, or 3.5% for the year ended December 31, 2013 compared to 2012, primarily as a result of increases in average prices received for oil and natural gas, and an increase in natural gas production of 9.7 Bcf, or 10.4%. Total production remained relatively unchanged in 2013 compared to 2012; however, natural gas comprised a larger portion of total production in 2013 as production from the Mid-Continent and Gulf of Mexico, which contains a higher percentage of natural gas than production from the Permian Basin, comprised a larger percentage of total production in 2013.

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 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, which had higher production costs inherent with offshore operations. Production expenses increased $39.5 million, or 8.2%, in 2013 from 2012, primarily due to $32.7 million in CO_2 under delivery penalties incurred for the year ended December 31, 2013 under a treating agreement with Occidental that became effective in the fourth quarter of 2012. See further discussion of the treating agreement with Occidental in "Liquidity and Capital Resources - Contractual Obligations and Off-Balance Sheet Arrangements." Production expense for 2013 was $15.38 per Boe, up from the rate of $14.31 per Boe in 2012. This increase is primarily a result of the under delivery penalties and, to a lesser extent, higher costs associated with production from properties located in the Gulf of Mexico, which comprised a larger percentage of total production in 2013 than in 2012.

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. Production taxes decreased by approximately $14.9 million, or 31.6% for 2013 compared to 2012, as production from the Mid-Continent and Gulf Properties comprised approximately 82.5% of total 2013 production compared to approximately 57.1% of 2012 production. Production from the Gulf of Mexico is not subject to production taxes. Additionally, wells drilled in the Mississippian formation in Oklahoma are part of a tax credit incentive program that reduces the combined statutory rates applicable to the first four years of production from such wells.

Depreciation and depletion for the Company’s oil and natural gas properties decreased by $133.4 million for the year ended December 31, 2014, compared to 2013. This decrease is largely a result of the decrease in the Company’s combined production volumes for the 2014 period as well as a decrease in the 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. Depreciation and depletion for the Company's oil and natural gas properties was consistent for the years ended December 31, 2013 and 2012.

Accretion of asset retirement obligations decreased $27.7 million for the year ended December 31, 2014, compared to 2013, primarily due to the assumption by the buyer of asset retirement obligations associated with the Gulf Properties sold in February 2014. Accretion of asset retirement obligations increased $7.8 million for the year ended December 31, 2013 from 2012, primarily as a result of the increase in future plugging and abandonment obligations associated with the oil and natural gas properties located in the Gulf of Mexico that were acquired during the second quarter of 2012.

Impairment of $164.8 million for the year ended December 31, 2014 was incurred in the first quarter of 2014 and was due to a full cost ceiling limitation resulting from the divestiture of the Gulf Properties 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. During the year ended December 31, 2012, the Company recorded a $235.4 million impairment to the carrying value of goodwill. Primarily as a result of a decrease in the Company's probable reserves as of December 31, 2012, which is a significant component in the determination of the fair value of the applicable reporting unit, the carrying value of the reporting unit exceeded its fair value such that the entire carrying value of the Company's goodwill was impaired. For additional information regarding the goodwill impairment, see "Note 8—Impairment" to the Company's consolidated financial statements in Item 8 of this report.

The Company recorded a (gain) loss on commodity derivative contracts of $(334.0) million, $47.1 million and $(241.4) million for the years ended December 31, 2014, 2013 and 2012, respectively, as reflected in income from operations for the exploration and production segment, which include net cash payments (receipts) upon settlement of $32.3 million, $(0.8) million and $(91.4) million, respectively. Included in these net cash payments 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. For the year ended December 31, 2012, 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.

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.

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 Oil Field Services Segment

The financial results of the Company’s drilling and oil field services segment depend primarily on demand and prices that can be charged for its services. On a consolidated basis, drilling and oil field service revenues earned and expenses incurred in performing services for third parties, including third-party working interests in wells the Company operates, are included in drilling and services revenues and cost of sales. Drilling and oil field service revenues earned and expenses incurred in performing services for the Company’s own account are eliminated in consolidation. The primary factors affecting the results of the Company’s drilling and oil field services segment are the rates received on rigs drilling for third parties, the number of days drilling for third parties and the amount of oil field services provided to third parties.

Set forth in the table below is financial and operational information for the drilling and oil field services segment for the years ended December 31, 2014, 2013 and 2012.

	Year Ended December 31,		
	2014	2013	2012
Results (in thousands)			
Revenues	$192,944	$187,456	$379,345
Inter-segment revenue	(116,856)	(120,815)	(262,712)
Total revenues	76,088	66,641	116,633
Operating expenses	86,225	95,692	104,722
Impairment	27,427	11,104	—
(Loss) income from operations	$(37,564)	$(40,155)	$11,911
Drilling rig statistics			
Average number of operational rigs owned during the period	27.0	29.0	30.0
Average number of rigs working for third parties	4.8	4.4	9.4
Number of days drilling for third parties	1,749	1,603	2,613
Average drilling revenue per day per rig drilling for third parties(1)	$14,985	$14,610	$16,919
Rig status as of December 31			
Working for SandRidge	10	11	14
Working for third parties(2)	—	6	10
Idle (3)	15	10	6
Total operational	25	27	30
Non-operational(4)	2	3	1
Total rigs	27	30	31

(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) Includes five rigs receiving stand-by rates from third parties at December 31, 2012.

(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 and 2012 were stacked. Non-operational rigs at December 31, 2013 were held for sale.

Drilling and oil field 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 interest 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 oil field 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.

Demand for the Company's drilling and oilfield services in the Permian region declined significantly in the latter half of 2014 as a result of the Company's fulfillment of its drilling obligation with the Permian Trust and the downward trend in oil prices that began during that period. At December 31, 2014, the Company determined the future use of its drilling and oilfield services assets in this region was limited and recorded an impairment of $24.3 million on these assets. In the first quarter of 2015, the Company decided to discontinue all remaining drilling and oil field services operations in the Permian region. The Company also recorded an impairment of approximately $3.1 million in the second quarter of 2014 on certain drilling assets identified for sale in order to adjust their carrying values to fair value. These impairments, while partially offset by an increase in revenue, resulted in a loss from operations of $37.6 million for the year ended December 31, 2014.

Drilling and oil field services segment revenues decreased $50.0 million for the year ended December 31, 2013 compared to 2012. The decrease in revenues was primarily attributable to a decrease in the average number of rigs working for third parties and a decrease in supplies sold to, and oil field services work performed for, wells that had been operated by the Company in the

Permian Basin prior to their sale. Drilling and oil field services segment operating expenses decreased $9.0 million during the year ended December 31, 2013 compared to 2012 due primarily to the decrease in work performed in the Permian Basin, which was significantly offset by costs associated with maintenance performed on rigs that were stacked as a result of the sale of the Permian Properties. For the year ended December 31, 2013, the Company recorded an impairment of approximately $11.1 million on certain drilling assets identified for sale in order to adjust their carrying values to fair value. The impairment and decrease in revenue resulted in a loss from operations of $40.2 million for the year ended December 31, 2013.

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. The Company owns and operates two gas treating plants in west Texas, which remove CO_2 from natural gas production and deliver residue gas to nearby pipelines. Throughout 2012, the Company diverted its high CO_2 natural gas production from its gas treating plants to the Century Plant while it was being tested and commissioned. Upon substantial completion of the Century Plant in late 2012, natural gas volumes delivered by the Company for processing at the Century Plant became subject to the terms of the 30-year treating agreement with Occidental, which contains minimum CO_2 delivery requirements. All natural gas produced in the WTO during 2013 and 2014 was processed at the Century Plant. Due to the continued decline in natural gas production in the WTO resulting from the lack of drilling activity in the area, volumes currently produced in the WTO and delivered to the Century Plant for processing are not sufficient to use all of the available treating capacity at the Century Plant. Due to the sensitivity of drilling to market prices for natural gas, drilling activity in the WTO will likely remain very limited if natural gas prices remain low. As a result, the Company currently anticipates little to no use of its treating plants in future periods. See further discussion of the CO_2 treating agreement in "Liquidity and Capital Resources—Contractual Obligations and Off-Balance Sheet Arrangements."

Set forth in the table below is financial information for the midstream services segment for the years ended December 31, 2014, 2013 and 2012.

	Year Ended December 31,		
	2014	2013	2012
Results (in thousands)			
Operating revenues	$142,987	$156,640	$116,659
Construction contract	—	23,349	—
Inter-segment revenue	(87,593)	(100,529)	(77,824)
Total revenues	55,394	79,460	38,835
Operating expenses	63,927	73,744	52,179
Construction contract	—	23,349	—
Impairment	561	3,934	59,683
Loss from operations	$(9,094)	$(21,567)	$(73,027)
Gas Marketed			
Volumes (MMcf)	7,343	8,006	9,367
Price	$4.18	$3.56	$2.63

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.

Midstream services segment operating revenues and expenses, excluding construction contract revenue and expenses, increased $17.3 million and $21.6 million, respectively, for the year ended December 31, 2013 compared to the same period in 2012. These increases in operating revenue and expenses were due to an increase of $0.95 per Mcf in the average price received for natural gas purchased and marketed in west Texas during the year ended December 31, 2013 and an increase in revenue from and expenses related to electrical transmission services provided by the Company’s expanded electrical infrastructure in the Mid-Continent to third-party working interest owners. These increases were slightly offset by a 1.4 Bcf decrease in third-party volumes processed and marketed for the year ended December 31, 2013 compared to 2012 as a result of decreased natural gas production in west Texas.

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 Contracts” to the Company’s consolidated financial statements in Item 8 of this report.

Midstream services segment expenses for the years ended December 31, 2013 and 2012 include impairments of $3.9 million and $59.7 million, respectively, on its natural gas treating plants in west Texas due to the anticipation that their future use would be limited as discussed under Gas Treating Plants above.

Consolidated Results of Operations

Revenues

The Company’s consolidated revenues for the years ended December 31, 2014, 2013 and 2012 are presented in the table below.

	Year Ended December 31, 2014	2013	2012
	(In thousands)		
Revenues			
Oil, natural gas and NGL	$1,420,879	$1,820,278	$1,759,282
Drilling and services	76,088	66,586	116,633
Midstream and marketing	55,658	58,304	40,486
Construction contract	—	23,349	—
Other	6,133	14,871	18,241
Total revenues(1)	$1,558,758	$1,983,388	$1,934,642

(1) Includes $150.4 million, $199.3 million and $181.2 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, 2014, 2013 and 2012, 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 Oil Field Services Segment” and discussion of significant midstream and marketing and construction contract revenues under “Results by Segment—Midstream Services Segment.”

Expenses

The Company’s consolidated expenses for the years ended December 31, 2014, 2013 and 2012 are presented below.

	Year Ended December 31, 2014	2013	2012
	(In thousands)		
Expenses			
Production	$346,088	$516,427	$477,154
Production taxes	31,731	32,292	47,210
Cost of sales	56,155	57,118	68,227
Midstream and marketing	49,905	53,644	39,669
Construction contract	—	23,349	—
Depreciation and depletion—oil and natural gas	434,295	567,732	568,029
Depreciation and amortization—other	59,636	62,136	60,805
Accretion of asset retirement obligations	9,092	36,777	28,996
Impairment	192,768	26,280	316,004
General and administrative	113,991	207,920	241,682
Employee termination benefits	8,874	122,505	—
(Gain) loss on derivative contracts	(334,011)	47,123	(241,419)
Loss on sale of assets	10	399,086	3,089
Total expenses(1)	$968,534	$2,152,389	$1,609,446

(1)

Includes $51.0 million, $157.0 million and $75.4 million of expenses attributable to noncontrolling interests in consolidated VIEs, after considering the effects of intercompany eliminations, for the years ended December 31, 2014, 2013 and 2012, respectively. The expenses attributable to noncontrolling interest in consolidated VIEs include $29.9

million of allocated full cost ceiling impairment for the year ended December 31, 2014 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 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 Oil Field 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, 2013, primarily consists of a $2.9 million impairment of a corporate asset based on plans to sell these assets in 2013 and 2014, 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. Other impairment expense for the year ended December 31, 2012 consists primarily of a $19.6 million impairment of the Company's CO_2 compression facilities recorded in connection with the completion of the Century Plant. 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 decreased $93.9 million, or 45.2%, for the year ended December 31, 2014 compared to 2013 due to a decrease of $22.2 million in costs related to a stockholder consent solicitation that occurred in 2013, as well as decreases of (i) $44.5 million in compensation, (ii) $9.8 million in professional services costs, (iii) $3.8 million in promotional and advertising costs, and (iv) $5.5 million in other corporate support costs primarily as a result of corporate cost cutting measures and a decrease in headcount during 2014.

General and administrative expenses decreased $33.8 million, or 14.0% for the year ended December 31, 2013 from 2012, primarily due to decreases of (i) $23.5 million in legal settlement costs, (ii) $12.0 million in acquisition costs, (iii) $6.8 million in promotional and advertising costs as a result of corporate cost cutting measures and a decrease in headcount during 2013, and (iv) a decrease of $5.6 million in legal and other professional services costs. These decreases were partially offset by a $20.4 million increase in costs related to a stockholder consent solicitation.

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 Income Attributable to Noncontrolling Interest

The Company's other income (expense), taxes and net income attributable to noncontrolling interest for the years ended December 31, 2014, 2013 and 2012 are reflected in the table below.

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Other income (expense)			
Interest expense	$(244,109)	$(270,234)	$(303,349)
Bargain purchase gain	—	—	122,696
Loss on extinguishment of debt	—	(82,005)	(3,075)
Other income, net	3,490	12,445	4,741
Total other expense	(240,619)	(339,794)	(178,987)
Income (loss) before income taxes	349,605	(508,795)	146,209

Income tax (benefit) expense	(2,293)	5,684	(100,362)
Net income (loss)	351,898	(514,479)	246,571
Less: net income attributable to noncontrolling interest	98,613	39,410	105,000
Net income (loss) attributable to SandRidge Energy, Inc.	$253,285	$(553,889)	$141,571

Interest expense for the years ended December 31, 2014, 2013 and 2012 consisted of the following:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Interest expense			
Interest expense on debt	$254,475	$277,746	$290,560
Amortization of debt issuance costs, discounts and premium	9,954	11,127	16,980
Dynamic Acquisition committed financing fee	—	—	10,875
Loss on interest rate swaps	—	14	1,189
Capitalized interest	(19,718)	(16,691)	(14,789)
Total	244,711	272,196	304,815
Less: interest income	(602)	(1,962)	(1,466)
Total interest expense	$244,109	$270,234	$303,349

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. Total interest expense decreased $33.1 million for the year ended December 31, 2013 compared to 2012, primarily as a result of a reduction in interest expense associated with the senior notes repurchased and redeemed in 2012 and in the first quarter of 2013, which was partially offset by the incurrence of interest on the senior notes issued in 2012 for the full year of 2013. In addition, committed financing fees of $10.9 million associated with the Dynamic Acquisition were expensed during the year ended December 31, 2012 when the Company chose to issue senior notes to fund the cash portion of the purchase price rather than to utilize previously secured committed financing. 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 bargain purchase gain recorded during the year ended December 31, 2012 resulted from the excess of net assets acquired over consideration paid in the Dynamic Acquisition in April 2012. The Company was able to acquire Dynamic for less than the estimated fair value of its net assets due to their offshore location resulting in less bidding competition.

In connection with the March 2013 redemption of the Company's 9.875% Senior Notes due 2016 and 8.0% Senior Notes due 2018, the Company recognized a loss on extinguishment of debt of $82.0 million for the year ended December 31, 2013. The Company recognized a loss on extinguishment of debt of $3.1 million for the year ended December 31, 2012 in connection with the tender offer to repurchase the Company's Senior Floating Rate Notes due 2014 in August 2012. The losses on extinguishment represent 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.

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 amount of $1.3 million in the Company's gross unrecognized tax benefits following a favorable outcome pertaining to the Company's state income tax audits and a reduction in the amount of $1.2 million in federal alternative minimum tax ("AMT") associated with the tax year ended December 31, 2013. With respect to the AMT, the Company reduced the current liability and a corresponding deferred tax asset each upon finalizing and filing the Company's federal income tax return for the year ended December 31, 2013. 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 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. The Company reported an income tax benefit of $100.4 million for the year ended December 31, 2012. The benefit was primarily attributable to the release of a portion of the Company’s valuation allowance against its net deferred tax asset during the period. A net deferred tax liability of $100.3 million recorded as a result of the Dynamic Acquisition reduced the Company’s existing net deferred tax asset position, resulting in a corresponding reduction in the valuation allowance against the net deferred tax asset.

Net income attributable to noncontrolling interest represents the portion of net income attributable to third-party ownership in the Company’s consolidated VIEs and subsidiaries. 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.

Net income attributable to noncontrolling interest decreased to $39.4 million for the year ended December 31, 2013 from $105.0 million in 2012 due primarily to the $71.7 million loss on the sale of the Permian Properties attributable to noncontrolling interest during 2013. Additionally, net losses were recognized on the Royalty Trusts' derivative contracts in the 2013 period compared to net gains recognized during 2012. These decreases were partially offset by the inclusion of a full year of operating income for 2013 from the Mississippian Trust II, which completed its initial public offering in April 2012.

Liquidity and Capital Resources

The Company's primary sources of liquidity and capital resources are cash flows from operating activities, borrowings under the senior credit facility, proceeds from monetizations of assets and the issuance of equity and debt securities. As described in Item 1 "Business—Divestitures," the Company received proceeds of approximately $702.6 million, net of working capital adjustments and post-closing adjustments, for the sale of its Gulf Properties in February 2014 and received proceeds of approximately $2.6 billion, for the sale of its Permian Properties in February 2013. The recent decline in oil and natural gas prices has had a negative effect on the Company's cash flows from operations and sustained low oil prices will require the Company to incur additional indebtedness under its senior credit facility to fund planned capital expenditures and other operations. Continued low oil and natural gas prices, or further declines in such prices, could also adversely affect the Company's ability to incur additional indebtedness or access the capital markets on favorable terms, or at all.

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, the payment of dividends on its outstanding convertible perpetual preferred stock, interest payments on its outstanding debt, the repurchase of shares of the Company's outstanding common stock and, from time to time, the repayment of long-term debt.

The Company's 2015 plan for capital expenditures, including expenditures related to the Company's drilling program for the Mississippian Trust II, is approximately $700.0 million, representing a 56% reduction from the Company's actual capital expenditures in 2014. The Company expects to fund its near term capital and debt service requirements and working capital needs with cash flow from operations, and available borrowing capacity under its senior credit facility. The senior credit facility, which has a borrowing base of $900.0 million, was undrawn at December 31, 2014 and had $100 million drawn at February 20, 2015. On each such date, the Company had, $11.6 million and $11.3 million 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. The Company has no maturities of long-term debt prior to 2020, and may choose to issue new long-term debt, subject to market availability, as an alternative to borrowing under its senior credit facility. Alternatively, the Company may issue equity or other non-debt securities in the capital markets, depending on market conditions, to address its funding requirements. In the longer term, the Company expects an increasing portion of its funding needs to be covered by cash flows from operations and may issue long-term debt or equity or monetize assets to cover any difference between cash flow from operations and capital needs. The Company's capital expenditures could be further curtailed if the Company's cash flows decline from expected levels. Because production from existing oil and natural gas wells declines over time, further reductions of capital expenditures used to drill and complete new oil and natural gas wells would likely result in lower levels of oil and natural gas production in the future.

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, prices for West Texas Intermediate light sweet crude oil (“WTI”), have declined from over $107.00 per Bbl in June 2014 to as low as $44.45 per Bbl in January 2015. Henry Hub natural gas prices declined from over $8.15 per MMBtu in February 2014 to $2.74 per MMBtu in December 2014. The Company’s derivative arrangements serve to mitigate a portion of the effect of this price volatility on its cash flows. The Company has in place fixed price swap and collar contracts for a majority of its anticipated oil production and a portion of its natural gas production in 2015 and for a portion of its anticipated oil production in 2016.

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 a full cost pool ceiling impairment. In addition, continued low oil and natural gas prices or further declines in such prices could result in a reduction in the size of the borrowing base under the senior credit facility, which would limit borrowings to fund capital expenditures. On February 23, 2015, the Company and its lenders further amended the credit agreement to address the risk that, in light of depressed oil and natural gas prices, the Company would breach certain financial covenants in 2015. See additional discussion of the senior credit agreement amendment under “Cash Flows—Senior Credit Facility.” There is significant risk that the Company will be unable to comply with the financial covenants under its amended senior credit facility if the current levels of oil or natural gas prices continue for a prolonged period or if there are further sustained declines in such prices, without other mitigating circumstances. The failure to comply with such covenants, absent a waiver or amendment of the applicable provisions of the credit agreement by the lenders under the credit facility, could result in a default, which, if left uncured, could lead to an event of default under the credit facility. Such an event of default would permit the lenders under the senior credit facility to, among other things, terminate the commitments of each lender, require cash collateralization of outstanding letters of credit, and/or declare all outstanding loans immediately due and payable. An event of default would trigger cross-default under certain of the Company’s other financing instruments, including the indentures governing its senior notes. The application of any of the lender remedies under the credit facility could have a material adverse effect on the Company’s financial position.

In light of current commodity prices and the Company’s leverage position, the Company is analyzing a variety of transactions and mechanisms designed to reduce debt and/or increase net income, including the monetization of non-income producing assets, the retirement or purchase of its outstanding debt securities through cash purchases and/or exchanges for equity or other Company securities in open market purchases, privately negotiated transactions or otherwise and opportunistic acquisitions. Such transactions, if any, will depend on prevailing market conditions, the Company’s liquidity requirements, contractual restrictions and other factors.

As of December 31, 2014, the Company’s cash and cash equivalents were $181.3 million, including $9.4 million attributable to the Company’s consolidated VIEs which is available to satisfy only obligations of the VIEs. The Company had approximately $3.2 billion in total debt outstanding and $11.6 million in outstanding letters of credit with no amount outstanding under its senior credit facility at December 31, 2014. As of and for the year ended December 31, 2014, the Company was in compliance with applicable covenants under its senior credit facility and outstanding senior notes. As of February 20, 2015, the Company’s cash and cash equivalents were approximately $52.9 million, including $52.8 million attributable to the Company’s consolidated VIEs. Additionally, there was $100.0 million outstanding under the Company’s senior credit facility and $11.3 million in outstanding letters of credit.

The Company and one of its wholly owned subsidiaries are parties to a development agreement with the Mississippian Trust II that obligates the Company to drill, or cause to be drilled, a specified number of wells within a specific area of mutual interest for the Royalty Trust by December 31, 2016. The Company fulfilled its drilling obligations to the Mississippian Trust I during the second quarter of 2013 and to the Permian Trust in the fourth quarter of 2014 and expects to satisfy its drilling obligation to the Mississippian Trust II in the first quarter of 2015. In addition, production targets contained in certain gathering and treating arrangements require the Company to incur capital expenditures or make associated shortfall payments. See additional discussion of these commitments under “Contractual Obligations and Off-Balance Sheet Arrangements.”

Working Capital

The Company’s working capital balance fluctuates as a result of changes in the fair value of its outstanding commodity derivative instruments and due to fluctuations in the timing and amount of its collection of receivables and payment of expenditures related to its exploration and production operations.

At December 31, 2014, the Company had a working capital surplus of $47.5 million compared to a surplus of $308.0 million at December 31, 2013. Current assets and current liabilities at December 31, 2014, decreased by $409.9

million and $149.4 million, respectively, compared to December 31, 2013. The decrease in current assets is primarily due to a $633.4 million decrease in cash and cash equivalents, resulting largely from cash used in operations, capital expenditures during 2014 and for common stock repurchases, which were partially offset by an increase of $278.6 million in the net asset position of the Company’s current derivative contracts. The decrease in current liabilities is primarily due to (a) a decrease of $129.1 million in accounts payable and accrued expenses largely due to (i) applying drilling prepayments made by third parties in 2013 against costs incurred during 2014, (ii) the sale of the Gulf Properties, 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, 2014, (b) a decrease of $87.1 million in the current asset retirement obligation resulting from the sale of the Gulf Properties and (c) a decrease of $34.3 million in the net liability position of the Company’s current derivative contracts. This decrease was partially offset by an increase of $95.8 million in the current deferred tax liability, which resulted primarily from the increase in value of the Company’s derivative contracts.

Cash Flows

The Company's cash flows for the years ended December 31, 2014, 2013 and 2012 are presented in the following table and discussed below:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Cash flows provided by operating activities	$621,114	$868,630	$783,160
Cash flows (used in) provided by investing activities	(857,241)	1,070,356	(2,555,945)
Cash flows (used in) provided by financing activities	(397,283)	(1,434,089)	1,874,870
Net (decrease) increase in cash and cash equivalents	$(633,410)	$504,897	$102,085

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 oil field 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, 2014 decreased by $247.5 million, or 28.5% compared to 2013 primarily due to a decrease in oil and natural gas 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.

Net cash provided by operating activities for the year ended December 31, 2013 increased $85.5 million, or 10.9% compared to 2012 due in part to an increase in prices received for oil and natural gas production. Also contributing to the increase were changes in operating assets and liabilities during 2013, primarily related to the timing of cash receipts and disbursements. These changes included a decrease in accounts receivable which was partially offset by an increase in cash paid to settle the Company's plugging and abandonment obligations, primarily on Gulf of Mexico properties acquired during the second quarter of 2012.

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.

Cash flows used in investing activities were $857.2 million for the year ended December 31, 2014 compared to cash flows provided by investing activities of $1.1 billion for the year ended December 31, 2013. During 2014, the Company had capital expenditures, excluding acquisitions of $1.6 billion, which were partially offset by proceeds from the sale of assets of $714.5 million, primarily as a result of 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. Cash flows used by investing activities of $2.6 billion for the year ended December 31, 2012 primarily reflect capital expenditures incurred in the continued development of the Company's oil properties, primarily in the Mid-Continent, and the acquisition of oil and natural gas properties located in the Gulf of Mexico, which were partially offset by proceeds from the sale of assets during 2012.

Capital Expenditures. The Company’s capital expenditures, on an accrual basis, by segment for the years ended December 31, 2014, 2013 and 2012 are summarized below:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Capital expenditures			
Exploration and production	$1,508,100	$1,319,012	$2,001,490
Drilling and oil field services	18,385	7,125	27,527
Midstream services	44,606	55,706	80,413
Other	37,798	42,040	114,552
Capital expenditures, excluding acquisitions	1,608,889	1,423,883	2,223,982
Acquisitions	18,384	17,028	840,740
Total	$1,627,273	$1,440,911	$3,064,722

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. Capital expenditures, excluding acquisitions, decreased by $800.1 million for the year ended December 31, 2013 compared to 2012, primarily as a result of an increased focus on capital discipline by the Company’s management.

During the years ended December 31, 2014 and 2013, the Company received payments for drilling carries from Atinum and Repsol 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.

Cash Flows from Financing Activities

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.

The Company’s financing activities used $1.4 billion in cash for the year ended December 31, 2013 compared to providing $1.9 billion of cash in the same period in 2012. This change was primarily due to making cash payments in 2013 for the redemption of the 9.875% Senior Notes due 2016 and 8.0% Senior Notes due 2018, as noted above, compared to receiving net proceeds in 2012 of (i) $1.1 billion from the issuance of the 7.5% Senior Notes due 2023 and additional 7.5% Senior Notes due 2021, (ii) $730.1 million from the issuance of the 8.125% Senior Notes due 2022, (iii) $587.1 million from the issuance of common units by the Mississippian Trust II, and (iv) $139.4 million from the sale of Mississippian Trust I and Permian Trust common units owned by the Company.

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, excluding broker fees and commissions, and were immediately retired. 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.

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Indebtedness

Long-term debt consists of the following at December 31, 2014 (in thousands):

8.75% Senior Notes due 2020, net of $4,598 discount	$445,402
7.5% Senior Notes due 2021, including premium of $3,486	1,178,486
8.125% Senior Notes due 2022	750,000
7.5% Senior Notes due 2023, net of $3,452 discount	821,548
Total debt	$3,195,436

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, 2014, the Company was in compliance with all of the covenants contained in the indentures governing its outstanding Senior Notes.

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. In connection with the amendment and restatement of the senior credit facility in October 2014, the Company's borrowing base was increased to $1.2 billion from $775.0 million, and the availability of the borrowing base limited to a facility amount of $900.0 million. On February 23, 2015, in connection with an amendment to the senior credit agreement, the borrowing base was reduced to $900.0 million from $1.2 billion. The next scheduled redetermination is expected to take place in October 2015. Quarterly, the Company pays a commitment fee assessed at an annual rate ranging from 0.375% to 0.5% on any available portion of the senior credit facility. The borrowing base is determined based upon the discounted present value of future cash flows attributable to the Company's proved reserves.

At December 31, 2014, the Company had no amount outstanding under the senior credit facility and $11.6 million in outstanding letters of credit, which reduced the availability under the senior credit facility to $888.4 million at December 31, 2014. As of and during the year ended December 31, 2014, the Company was in compliance with all applicable financial covenants under the senior credit facility.

On November 14, 2014, the Company and its lenders amended the senior credit agreement to waive certain defaults that may have arisen as a result of the Company's failure to timely deliver its quarterly financial statements for the quarter ended September 30, 2014 and extend the period for delivering the unaudited condensed consolidated statements for such interim period.

On February 23, 2015, the Company and its lenders further amended the credit agreement to address the risk that, in light of depressed oil and natural gas prices, the Company would breach certain financial covenants in 2015. The amendment, among other things, (i) temporarily suspends until June 30, 2016 the financial covenant requiring maintenance of certain levels for the ratio of total net debt to EBITDA, (ii) adopts the financial covenants described below, (iii) permits the incurrence of additional junior debt, which may be secured, in an amount not to exceed $500.0 million, and (iv) increases the applicable margin used in the calculation of interest under the senior credit facility.

The amended senior credit facility is available to be drawn on subject to limitations based on its terms and certain financial covenants, including maintenance of agreed upon levels for the (i) ratio of total debt secured by assets of the

Company and certain of its subsidiaries to EBITDA, which may not exceed 2.25:1.00 at each quarter end, calculated using the last four completed fiscal quarters, (ii) ratio of EBITDA to interest expense, which must be at least 2.00:1.00 at March 31, 2015 and June 30, 2015, 1.75:1.00 at September 30, 2015, 1.50:1.00 at each quarter end from December 31, 2015 to September 30, 2016, and 2.00:1.00 at December 31, 2016 and thereafter, calculated using the last four completed fiscal quarters, (iii) ratio of current assets to current liabilities, which must be at least 1.00:1.00 at each quarter end, and (iv) ratio of total net debt to EBITDA, which may not exceed 6.25:1.00 at June 30, 2016, 6.00:1.00 at September 30, 2016 and December 31, 2016, 5.50:1.00 at March 31, 2017 and June 30, 2017, 5.00:1.00 at September 30, 2017 and December 31, 2017 and 4.50:1.00 at March 31, 2018 and thereafter, calculated using annualized EBITDA for the fiscal quarter ended June 30, 2016 and the two subsequent fiscal quarters and otherwise calculated using the last four completed fiscal quarters. If no amounts are drawn under the senior credit facility when calculating the ratio of total net debt to EBITDA, the Company’s debt is reduced by its cash balance in excess of $10.0 million. In 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 derivative contracts are disregarded.

Additionally, 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 $500.0 million, 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. At February 23, 2015, the Company had neither incurred junior debt nor entered into any intercreditor agreement.

Redemption of Senior Notes. In March 2013, the Company redeemed $365.5 million aggregate principal amount of its 9.875% Senior Notes due 2016 and $750.0 million aggregate principal amount of its 8.0% Senior Notes due 2018 for total consideration of $1,061.34 per $1,000 principal amount and $1,052.77 per $1,000 principal amount, respectively. The premium paid to redeem these notes and the expense incurred to write off the remaining associated unamortized debt issuance costs resulted in a loss on extinguishment of debt of $82.0 million for the year ended December 31, 2013. The redemption was funded by a portion of the proceeds received from the sale of the Permian Properties.

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, 2014, 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, 2014 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)	$4,923,076	$250,313	$500,625	$500,625	$3,671,513
Gas gathering agreement(2)	292,719	42,334	84,263	83,528	82,594
Transportation and throughput agreements	71,159	12,467	24,965	21,055	12,672
Third-party drilling rig agreements(3)	31,683	30,009	1,674	—	—
Asset retirement obligations	54,402	—	—	—	54,402
Operating leases and other(4)	35,264	5,691	4,740	1,884	22,949
Total	$5,408,303	$340,814	$616,267	$607,092	$3,844,130

(1) Includes interest on long-term debt.

(2) Consists of a gas gathering agreement to deliver certain minimum volumes of natural gas to PGC, an unconsolidated variable interest entity. Pursuant to the agreement, the base fee for gathering services can be reduced if certain criteria are met. The amounts above are based on the base fee per the agreement.

(3) 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.

(4)

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 IRS annual limitations on qualified 401(k) retirement plans.

In addition to the contractual obligations included in the table above, the Company has a development agreement with the Mississippian Trust II and a treating agreement commitment with Occidental, the future effects of which are not reflected in its consolidated balance sheet at December 31, 2014, and are described below.

Development Agreements with Royalty Trusts. The Company’s development agreement with the Mississippian Trust II obligates the Company to drill, or cause to be drilled, a specified number of wells within an area of mutual interest by December 31,

2016. The Company fulfilled its drilling obligation to the Mississippian Trust I during the second quarter of 2013 and fulfilled its drilling obligation to the Permian Trust during the fourth quarter of 2014. The estimated cost to fulfill the drilling obligation remaining at December 31, 2014 totaled approximately $8.8 million.

Treating Agreement. The Company is required to deliver a total of approximately 3,200 Bcf of CO_2 during the term of a treating agreement with Occidental, which ends in 2041. The Company is obligated to pay Occidental $0.25 per Mcf to the extent minimum annual CO_2 volume requirements are not met. Through December 31, 2014, the Company had delivered to Occidental 54.7 Bcf of CO_2, which is 300.1 Bcf less than the cumulative minimum for the same period and had accrued associated annual shortfall penalties of approximately $75.0 million. Based on current projected natural gas production levels, the Company expects to accrue between approximately $31.0 million and $38.0 million during the year ending December 31, 2015 for amounts related to the Company's anticipated shortfall in meeting its 2015 annual delivery obligations. If such under delivered volumes are not made up with commensurate over deliveries in the future, the Company will be obligated to pay Occidental $0.70 per Mcf (approximately $210.1 million total) in 2041, which amount has not been accrued as the Company does not currently believe such payment is probable.

If CO_2 volumes delivered to Occidental do not materially increase from current levels, the Company will have the right, beginning in 2020, to reduce future minimum annual CO_2 volume requirements under the agreement by paying Occidental an amount equal to the present value of $0.70 multiplied by such reduced CO_2 volume requirements as designated by the Company. As of December 31, 2014, if the Company were to cease delivering natural gas for processing and made no future CO_2 deliveries from such date until 2020, the Company would be required to pay annual delivery shortfall penalties, in the aggregate, of approximately $292.6 million for the contract years 2012 through 2019, which includes $75.0 million for penalties incurred through December 31, 2014. Further, by paying approximately $291.4 million in 2020, which includes the present value of $0.70 multiplied by delivery shortfalls incurred through such date, the Company could adjust the future CO_2 volume requirements to zero. This amount will continue to decrease as future deliveries of CO_2 are made. The Company also may terminate the treating agreement at any time, which would require a termination payment by the Company to Occidental of an amount equal to (a) the present value of $0.70 multiplied by the remaining CO_2 volumes required to be delivered under the agreement, plus (b) Occidental's current net book value of the Century Plant.

The Company has first priority on daily available processing capacity for properly nominated and delivered volumes; however, based on cumulative delivered volumes as of the balance sheet date, if the Company makes no further deliveries from that date until 2025, beginning in 2025 the Century Plant, even if fully utilized, would not have adequate capacity to allow the Company to deliver CO_2 volumes attributable to previously incurred delivery shortfalls at that time.