SANDRIDGE ENERGY INC
Form 10-K/A
January 08, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K/A
(Amendment No. 1)

(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, 2013

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 28, 2013 was approximately $2.3 billion based on the closing price as quoted on the New York Stock Exchange. As of February 21, 2014, there were 495,085,274 shares of our common stock outstanding.
DOCUMENTS INCORPORATED BY REFERENCE
Portions of the Company's definitive proxy statement for the 2014 Annual Meeting of Stockholders are incorporated by reference in Part III.

EXPLANATORY NOTE

SandRidge Energy, Inc. (the “Company”) is filing this amendment on Form 10-K/A (“Form 10-K/A”) to amend its Annual Report on Form 10-K for the year ended December 31, 2013, originally filed with the Securities and Exchange Commission (the “SEC”) on February 28, 2014 (“Original Filing”), to restate its consolidated financial statements and related footnote disclosures for the year ended December 31, 2013 as it relates to quarterly results included within “Note 26 - Quarterly Financial Results (Unaudited)” in Part II, Item 8 of this Form 10-K/A and to revise its consolidated financial statements and related footnote disclosures for the years ended December 31, 2013, 2012 and 2011 for other items discussed below. This Form 10-K/A also amends certain other items in the Original Filing, as listed in “Items Amended in this Form 10-K/A” below.

Restatement

On November 4, 2014, the Company filed a Current Report on Form 8-K, stating that (i) the consolidated financial statements of the Company for the periods ended December 31, 2013 and 2012 included in the Company’s Annual Reports on Form 10-K for the periods then ended and (ii) the unaudited consolidated financial statements of the Company for the periods ended June 30, 2014, March 31, 2014, September 30, 2013, June 30, 2013, and March 31, 2013 included in the Company’s Quarterly Reports on Form 10-Q for the periods then ended should no longer be relied upon due to potential changes related to the accrual of a liability associated with under delivery by the Company of CO_2 to Occidental Petroleum Corporation’s (“Occidental”) Century Plant in Pecos County, Texas (the “Century Plant”) or elsewhere.

Historically, based on its determination of the appropriate method of accounting for the annual CO_2 delivery shortfall penalty, the Company did not evaluate whether an accrual was needed within each quarterly period prior to the fourth quarter. As a result of consultation with the staff of the SEC, the Company has determined to adopt a different method of accounting for the penalty, which method considers, on a quarterly basis, whether a portion of the annual shortfall delivery penalty should be accrued at the end of each quarter. After applying this method, the Company concluded that it should restate its previously issued unaudited condensed consolidated financial statements for the quarterly and year-to-date periods ended June 30, 2014, March 31, 2014, September 30, 2013, June 30, 2013, and March 31, 2013. The effect of such corrections is to transfer a portion of the annual accrual that was previously recorded at year-end to certain of the quarter-end periods within such calendar year. Accordingly, the Company has restated its 2013 quarterly financial results included in “Note 26 - Quarterly Financial Results (Unaudited)” in Part II, Item 8 of this Form 10-K/A for this matter. No changes are being made to the annual accruals previously recorded.

As a result of the above-described adjustments, the Company is presenting in Forms 10-Q/A for the periods ended March 31, 2014 and June 30, 2014 (which are being filed concurrently herewith) restated consolidated financial statements for the periods indicated above. Corrections to statement of operations data for the quarters ended March 31, 2013 and June 30, 2013 will be reflected in the notes to the annual financial statements included in this 10-K/A as well as in the Forms 10-Q/A for the periods ended March 31, 2014 and June 30, 2014, respectively, and corrections to statement of operations data for the quarter ended September 30, 2013 will be reflected in the notes to the annual financial statements included in this 10-K/A as well as the Company’s quarterly report on Form 10-Q for the quarter ended September 30, 2014, which is also being filed concurrently herewith.

Revision

Additionally, as a result of consultation with the staff of the SEC, the Company has determined that construction of the Century Plant under a construction contract with Occidental should have been accounted for under the full cost method of accounting rather than the completed contract method of accounting. As of December 31, 2013, this change in accounting treatment had no impact on total assets, total liabilities, net income or retained earnings, but resulted in

(i) certain equal and offsetting adjustments within current assets or current liabilities as of December 31, 2013 and December 2012, (ii) certain equal and offsetting adjustments within items comprising net cash provided by operating activities for the years ended December 31, 2013, 2012 and 2011, and (iii) the removal of construction contract revenue and expense, each in the amount of $796.3 million, from the consolidated statement of operations for the year ended December 31, 2012. The Company has determined that none of these revisions are material to the consolidated financial statements for any of the periods presented in the Original Filing. The consolidated balance sheets as of December 31, 2013 and 2012, consolidated statements of cash flows for the years ended December 31, 2013, 2012 and 2011 and consolidated statement of operations for the year ended December 31, 2012 contained in Part II, Item 8 of this Form 10-K/A have been revised to include the impact of these items.

See the Company’s consolidated financial statements in Item 8 of this report for more information regarding the impact of the above-described restatement and revisions.

Internal Control Consideration

The Company's management has determined that the absence of an evaluation of whether an accrual for the annual CO_2 delivery shortfall penalty was required within each quarterly period prior to the fourth quarter, in accordance with its prior method of accounting, was a deficiency in its internal control over financial reporting that constitutes a material weakness, as defined by SEC regulations, at December 31, 2013, as discussed in Part II, Item 9A of this Form 10-K/A.

Items Amended in this Form 10-K/A

For the convenience of the reader, this Form 10-K/A sets forth the Original Filing, in its entirety, as modified and superseded where necessary to reflect the restatement and other revisions described above. The following items in the Original Filing have been amended as a result of, and to reflect, these modifications:

A. Part I, Item 1. Business
B. Part II, Item 6. Selected Financial Data
C. Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
D. Part II, Item 8. Financial Statements and Supplementary Data
E. Part II, Item 9A. Controls and Procedures
F. Part IV, Item 15. Exhibits and Financial Statement Schedules

This Form 10-K/A is presented as of the date of the Original Filing and does not reflect events occurring after that date, or modify or update the information contained therein in any way other than as required to reflect the restatement and revisions described above.

In accordance with Rule 12b-15 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), this Form 10-K/A includes certifications from the Company's Chief Executive Officer and Chief Financial Officer as of the date of this filing.

SANDRIDGE ENERGY, INC.
2013 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 25.

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 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," " "intend" or other words that convey the 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;
- 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;
- 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 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 owned interests in the Gulf of Mexico and Gulf Coast until February 2014, as discussed under “2014 Divestiture” below.

As of December 31, 2013, the Company had 4,388 gross (3,246.7 net) producing wells, a substantial portion of which it operates, and approximately 3,624,000 gross (2,438,000 net) total acres under lease. As of December 31, 2013, the Company had 30 rigs drilling in the Mid-Continent, one rig drilling in the Gulf of Mexico and three rigs drilling in west Texas. Total estimated proved reserves as of December 31, 2013 were 433.4 MMBoe, of which approximately 64% 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 disposal system, an electrical transmission system and a drilling rig and related oil field services business. As of December 31, 2013, the Company’s drilling rig fleet consisted of 27 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. The sale of its Gulf of Mexico and Gulf Coast oil and natural gas properties, discussed under “2014 Divestiture” below, represents a major step toward the achievement of that mission, by positioning SandRidge as a liquid-rich Mid-Continent company. 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 produced water 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.
- Develop Key Infrastructure Systems. By constructing a produced water 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 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.

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- 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 with predictable production profiles and a higher certainty of economic returns. Further, due to these low pressure and shallow characteristics, the Company is able to maintain a low-cost operating structure and manage service costs.
- 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.
- Mitigate Commodity Price Risk. The Company enters into derivative contracts to mitigate commodity price volatility inherent in the oil and natural gas industry. By increasing the predictability of cash inflows for a portion of its future production, the Company is better able to mitigate funding risks for its longer term development plans and lock-in rates of return on its capital projects.
- Pursue Opportunistic Acquisitions. The Company periodically reviews acquisition targets to complement its existing asset base. Accordingly, 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.
- Asset Monetization. The Company periodically evaluates its properties to identify opportunities to monetize assets to fund or accelerate development within its area of focus, 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.

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 has used and expects to use the remaining proceeds to fund its 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 own the Company’s Gulf of Mexico and Gulf Coast oil and natural gas properties (collectively, the “Gulf Properties”), for $750.0 million, subject to purchase price and post-closing adjustments, and the buyer’s assumption of approximately $370.0 million of related asset retirement obligations. Under the agreement, the Company agreed to guarantee certain plugging and abandonment obligations associated with the Gulf Properties on behalf of the buyer for a period of up to one year. Additionally, as part of the agreement, the buyer has agreed to indemnify the Company for any costs it may incur as a result of the guarantee. The Company retained a 2% overriding royalty interest in certain exploration prospects. The Company expects to use the proceeds from the sale to fund its drilling in the Mid-Continent.

At December 31, 2013, the Gulf Properties had associated proved reserves of 56.8 MMBoe with an estimated PV-10 value of $1.1 billion. See discussion of PV-10 under “—Proved Reserves.” For a reconciliation of PV-10 to Standardized Measure of Discounted Net Cash Flows (“Standardized Measure”), see “Management’s Discussion and Analysis -

Overview" in Item 7 of this report. The estimated Standardized Measure attributable to the Gulf Properties was approximately $842.5 million at December 31, 2013. For the year ended December 31, 2013, production, revenues and expenses, including direct operating expenses, depletion, accretion of asset retirement obligations and general and administrative expenses, for the Gulf Properties were 10.1 MMBoe, $627.2 million and $492.0 million, respectively.

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 23—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, 2013, 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	302.3	$ 3,427.4	52.1	15.9	2,621,018	1,849,244	$ 945.0
Gulf of Mexico / Gulf Coast	56.8	1,088.9	24.7	6.3	882,934	494,069	197.1
West Texas	74.3	675.3	11.9	17.1	120,217	95,170	198.2
Total	433.4	$ 5,191.6	88.7	13.4	3,624,169	2,438,483	$ 1,340.3

(1) For a reconciliation of PV-10 to Standardized Measure, see “—Proved Reserves.” The Company’s total Standardized Measure was $4.0 billion at December 31, 2013.
(2) Average daily net production for the month of December 2013.
(3) Estimated net proved reserves as of December 31, 2013 divided by production for the month of December 2013 annualized.
(4) Capital expenditures for the year ended December 31, 2013 on an accrual basis.

Properties

Mid-Continent

The Company held interests in approximately 2,621,000 gross (1,849,000 net) leasehold acres primarily in Oklahoma and Kansas at December 31, 2013. Associated proved reserves at December 31, 2013 totaled 302.3 MMBoe, 60% 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, 2013 included 1,858 gross (1,038.5 net) producing wells with an average working interest of 56%. The Company had 30 rigs operating in the Mid-Continent as of December 31, 2013, of which 26 were drilling horizontal wells, three were drilling vertical wells and one was drilling a saltwater disposal well. The Company drilled a total of 434 horizontal wells, 49 vertical wells and 28 saltwater disposal wells in this area during 2013.

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 Kansas. The top of this formation is encountered between approximately 4,000 and 7,000 feet and lies stratigraphically between the Pennsylvanian-aged Morrow formation and the Devonian-aged Woodford Shale formation. The Mississippian formation can reach 1,000 feet in gross thickness and the targeted porosity zone is between 50 and 100 feet in thickness. At December 31, 2013, the Company had approximately 2,535,000 gross (1,805,000 net) acres under lease in the Mississippian formation, of which approximately 58,000 gross (46,000 net) acres were included in the Mississippian Trust

II area of mutual interest. As the Company fulfilled its drilling obligation to the Mississippian Trust I in April 2013, the associated area of mutual interest terminated.
The Company has drilled approximately 1,060 wells in this formation as of December 31, 2013. From December 31, 2012 to December 31, 2013, the number of the Company's producing horizontal wells in the Mississippian formation increased from 649 to 1,167. Of the wells the Company drilled in the Mississippian formation during 2013, 86 wells are subject to the royalty interests of the Mississippian Trust I or Mississippian Trust II.
The Company's saltwater disposal system, constructed beginning in 2007, and electrical infrastructure, constructed by the Company's midstream services segment beginning in 2009, assist in the economically efficient production of oil and natural gas in the Mid-Continent. The saltwater disposal system, which included more than 150 active wells and approximately 865 miles of gathering lines at December 31, 2013, reduces the overall cost of water disposal, which directly reduces production costs. The Company's electrical infrastructure, which consisted of approximately 780 miles of power lines and five substations at December 31, 2013, 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.

Gulf Properties

The Company's Gulf Properties include oil and natural gas properties in the Gulf of Mexico and the Gulf Coast. The Company's Gulf of Mexico operations, a substantial portion of which were acquired during the second quarter of 2012 with the acquisition of Dynamic Offshore Resources, LLC (the "Dynamic Acquisition") and other Gulf of Mexico properties, primarily extend from the coast to more than 100 miles offshore and occur in federal and state waters with depths ranging from 10 to 1,380 feet. The Company's Gulf of Mexico oil and natural gas properties are shallow-water assets, with the exception of the Bullwinkle field, which is a deepwater asset. Additionally, the Company owns oil and natural gas interests in the Gulf Coast area, which encompasses the coastal plain from the southernmost tip of Texas through the southern portion of Louisiana.

As of December 31, 2013, the Company's Gulf Properties consisted of approximately 883,000 gross (494,000 net) leasehold acres, 634 gross (370.0 net) productive wells and approximately 350 miles of pipeline gathering systems. Associated proved reserves at December 31, 2013 were approximately 56.8 MMBoe, of which 70% were proved developed. The Company operates approximately 97% of these assets, based on PV-10 values as of December 31, 2013. The Company had one rig operating in the Gulf Properties as of December 31, 2013. In the Gulf Properties, the Company drilled a total of seven operated wells, participated in the drilling of four non-operated wells, performed 19 operated recompletions and participated in 14 non-operated recompletions during 2013.

The Company's pipeline gathering systems in the Gulf of Mexico, including the Bullwinkle platform, which serves as a processing hub for deepwater production, gather and transport production from third-party fields for which the Company receives production handling revenues.

As discussed in "2014 Divestiture" above, the Company sold its Gulf Properties and related pipeline gathering systems in February 2014.

West Texas

The Company's west Texas oil and natural gas properties include properties in the Permian Basin and the West Texas Overthrust ("WTO"). 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 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. 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 Company held interests in approximately 120,000 gross (95,000 net) leasehold acres in west Texas at December 31, 2013, of which approximately 16,000 gross (15,000 net) acres were included in the Permian Trust's area of mutual interest. Associated proved reserves at December 31, 2013 were 74.3 MMBoe, 77% of which were proved developed reserves. The Company's interests in west Texas as of December 31, 2013 included 1,896 gross (1,838.2 net) producing wells with an average working interest of 97%. The Company had three rigs operating in west Texas as of December 31, 2013 and drilled 213 wells in this area during 2013, of which 202 were subject to the Permian Trust's royalty interest. Low natural gas prices continued to limit development activity in the WTO, primarily a natural gas-producing region, during 2013.

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, substantially all 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 mandated 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 person 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 28 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 17 full-time employees, comprised of five degreed engineers and 12 engineering analysts/technicians with a minimum of a four-year degree in mathematics, economics, finance or other business or science field.

The Company maintains a continuous education program for its engineers and technicians 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 Reservoir Engineering Department reports directly to the Company’s Chief Operating Officer.

- the Reservoir Engineering Department follows comprehensive SEC-compliant internal policies to determine and report proved reserves including:
- confirming that reserves estimates include all properties owned and are based upon proper working and net revenue interests;
- reviewing and using in the estimation process data provided by other departments within the Company such as Accounting; and
- comparing and reconciling 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, Vice President 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,					
	2013		2012		2011	
Cawley, Gillespie & Associates, Inc.	64.6	%	—	%	—	%
Netherland, Sewell & Associates, Inc.	21.5	%	72.7	%	80.5	%
Lee Keeling and Associates, Inc.	—	%	24.9	%	15.6	%
Total	86.1	%	97.6	%	96.1	%

The remaining 13.9%, 2.4% and 3.9% of the Company's estimated proved reserves as of December 31, 2013, 2012 and 2011, 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 substantially all geographic locations as of December 31, 2013 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, 2013 is presented below.

	Geographic Locations—by Area by State
Cawley, Gillespie & Associates, Inc.	Mid-Continent - KS, OK
	Permian Basin—TX
Netherland, Sewell & Associates, Inc.	Gulf of Mexico
	Gulf Coast—LA, 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 26 years of practical experience in petroleum engineering and more than 24 years of experience estimating and evaluating reserve information;
- a registered professional engineer in the state of Texas; and

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- a Bachelor of Science Degree in Petroleum Engineering.

Netherland, Sewell & Associates, Inc.

- practical experience in petroleum engineering ranging from more than 14 years to more than 25 years and experience estimating and evaluating reserve information ranging from more than nine years to more than 20 years;
- Licensed Professional Engineers in the states of Texas and Louisiana and Licensed Professional Geoscientists in the State of Texas; and
- Bachelor of Science Degree in Civil Engineering, Bachelor of Science Degree in Mechanical Engineering, Bachelor of Science Degree in Geology, Master of Science Degree in Geology and Master of Business Administration Degree.

Lee Keeling and Associates, Inc.

- more than 57 years of practical experience in petroleum engineering and more than 53 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, 2013, NGLs comprised approximately 14% 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, 2013, 2012 and 2011, substantially all 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, 2013, 2012 and 2011, using first-day-of-the-month prices for each month. The Company estimates that approximately 88% of its current proved undeveloped reserves will be developed by the end of 2016 and all of its current proved undeveloped reserves will be developed by the end of 2018. See "Critical Accounting Policies and Estimates" in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates.

	December 31,		
	2013	2012	2011
Estimated Proved Reserves(1)			
Developed			
Oil (MMBbls)	83.9	136.6	101.6
NGL (MMBbls)	35.8	33.8	17.1
Natural gas (Bcf)	951.6	896.7	670.4
Total proved developed (MMBoe)	278.3	319.9	230.4
Undeveloped			
Oil (MMBbls)	58.7	125.4	112.9
NGL (MMBbls)	23.3	34.2	13.2
Natural gas (Bcf)	438.8	518.3	684.7
Total proved undeveloped (MMBoe)	155.1	246.0	240.2
Total Proved			
Oil (MMBbls)	142.6	262.0	214.5
NGL (MMBbls)	59.1	68.0	30.3
Natural gas (Bcf)	1,390.4	1,415.0	1,355.1
Total proved (MMBoe)(2)	433.4	565.9	470.6
PV-10 (in millions)(3)	$5,191.6	$7,488.4	$6,875.9
Standardized Measure of Discounted Net Cash Flows (in millions)(2)(4)	$4,017.6	$5,840.4	$5,216.3

(1) The Company's estimated proved reserves and the future net revenues, PV-10 and Standardized Measure were determined using a 12-month average price for oil and natural gas. The prices used in the Company's external and internal reserve reports yield weighted average wellhead prices, which are based on index prices and adjusted for transportation and regional price differentials. The index prices and the equivalent weighted average wellhead prices are shown in the table below.

	Index prices		Weighted average wellhead prices		
	Oil (per Bbl)	Natural gas (per Mcf)	Oil (per Bbl)(a)	NGL (per Bbl)	Natural gas (per Mcf)
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
December 31, 2011	$92.71	$4.12	$91.35	$46.33	$4.06

(a) At December 31, 2013 and 2012, the weighted average wellhead oil price is higher than the index price as a result of favorable location differentials for production in the Gulf of Mexico.

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(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, 2013	29.9	$781.6
December 31, 2012	38.2	$952.7
December 31, 2011	26.4	$932.8

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

(3) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using 12-month average prices for the years ended December 31, 2013, 2012 and 2011. 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 that 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,		
	2013	2012	2011
	(In millions)		
Standardized Measure of Discounted Net Cash Flows	$4,017.6	$5,840.4	$5,216.3
Present value of future income tax discounted at 10%	1,174.0	1,648.0	1,659.6
PV-10	$5,191.6	$7,488.4	$6,875.9

(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 145.5 MMBoe at December 31, 2011 to 235.8 MMBoe at December 31, 2012 and to 302.3 MMBoe at December 31, 2013, comprising a significant portion of the additions to the Company's proved reserves in both years. 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 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. During 2012, proved reserves in the Permian Basin, excluding production, increased by 59.5 MMBoe, primarily due to extensions and discoveries associated with successful drilling in the Central Basin Platform, which were slightly offset by downward revisions due mostly to pricing. 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,		
	2013	2012	2011
Reserves converted from proved undeveloped to proved developed (MMBoe)	44.6	42.6	50.3
Drilling capital expended to convert proved undeveloped reserves to proved developed reserves (in millions)	$437.6	$718.2	$817.0

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, are 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.

Excluding asset sales, the Company recognized a net addition to oil, natural gas and NGL reserves associated with proved undeveloped properties in 2011. Additional reserves attributable to extensions and discoveries, primarily in the Permian Basin and Mid-Continent areas as a result of successful drilling, more than offset downward revisions of reserve quantities from the Piñon Field in the WTO as a result of lower natural gas index prices. The 12-month average natural gas index price of $4.38 per Mcf for 2010 decreased to $4.12 per Mcf for 2011.

For additional information regarding changes in the Company’s proved reserves during the three years ended December 31, 2013, 2012 and 2011 see “Note 25—Supplemental Information on Oil and Natural Gas Producing Activities” to the Company’s consolidated financial statements in Item 8 of this report.

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, Fuhrman-Mascho and Piñon fields each contained more than 15% of the Company's total proved reserves at December 31, 2013, 2012 or 2011.

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)
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
Year Ended December 31, 2011				
Mississippi Lime Horizontal	1,204	6	8,332	2,598
Fuhrman-Mascho	3,282	487	1,633	4,041
Piñon	41	—	28,246	4,749

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, 2013 included 1,181 gross (730.9 net) producing wells and a 62% 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.

Piñon Field. The Piñon Field lies along the leading edge of the WTO in Pecos County, Texas. The primary reservoirs are the Tesnus sands (depths ranging from 3,500 to 6,000 feet), the Warwick Caballos chert (depths ranging from 5,000 to 8,000 feet) and the Dugout Creek Caballos chert (depths ranging from 7,000 to 10,000 feet). Low natural gas prices continue to limit development activity in this area.

Production and Price History

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

	Year Ended December 31,		
	2013	2012	2011
Production Data			
Oil (MBbls)	14,279	15,868	9,992
NGL (MBbls)	2,291	2,094	1,838
Natural gas (MMcf)	103,233	93,549	69,306
Total volumes (MBoe)	33,776	33,553	23,381
Average daily total volumes (MBoe/d)	92.5	91.7	64.1
Average Prices(1)			
Oil (per Bbl)	$97.58	$91.79	$90.31
NGL (per Bbl)	$35.16	$33.10	$44.58
Natural gas (per Mcf)	$3.36	$2.49	$3.50
Total (per Boe)	$53.89	$52.43	$52.47

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

	Year Ended December 31,		
	2013	2012	2011
Expenses per Boe			
Lease operating expenses			
Transportation	$1.29	$0.89	$0.71
Processing, treating and gathering(1)	1.05	1.18	1.59
Other lease operating expenses(2)	12.60	11.56	10.73
Total lease operating expenses	$14.94	$13.63	$13.03
Production taxes(3)	$0.96	$1.41	$1.97
Ad valorem taxes	$0.35	$0.59	$0.78

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

(2) For the years ended December 31, 2013 and 2012, includes $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, 2013. 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	1,326	805.3	532	233.2	1,858	1,038.5
Gulf of Mexico / Gulf Coast	317	189.3	317	180.7	634	370.0
West Texas	1,009	988.0	887	850.2	1,896	1,838.2
Total	2,652	1,982.6	1,736	1,264.1	4,388	3,246.7

Developed and Undeveloped Acreage

The following table sets forth information regarding the Company's developed and undeveloped acreage at December 31, 2013:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Area				
Mid-Continent	561,878	362,740	2,059,140	1,486,504
Gulf of Mexico / Gulf Coast	640,503	340,146	242,431	153,923
West Texas	52,322	46,775	67,895	48,395
Total	1,254,703	749,661	2,369,466	1,688,822

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, 2013 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, 2014	1,043,631	738,561
December 31, 2015	371,266	275,560
December 31, 2016	491,111	366,521
December 31, 2017 and later	146,974	105,735
Other(1)	316,484	202,445
Total	2,369,466	1,688,822

(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 twelve months ending December 31, 2014, as presented in the table above, are approximately 1,026,000 gross (722,000 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 2014 and expects to exercise such options or hold by production approximately 30% 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, 2013, the Company had 102 gross (78.0 net) operated wells drilling, completing or awaiting completion.

	2013							2012							2011						
	Gross	Percent		Net	Percent			Gross	Percent		Net	Percent			Gross	Percent		Net	Percent		
Completed Wells																					
Development																					
Productive	607	98.1	%	482.3	98.1	%		1,054	99.8	%	930.9	99.8	%		895	99.7	%	850.0	99.7	%	
Dry	12	1.9	%	9.5	1.9	%		2	0.2	%	1.7	0.2	%		3	0.3	%	2.9	0.3	%	
Total	619	100.0	%	491.8	100.0	%		1,056	100.0	%	932.6	100.0	%		898	100.0	%	852.9	100.0	%	
Exploratory																					
Productive	44	80.0	%	31.0	79.3	%		32	97.0	%	24.3	96.0	%		38	100.0	%	33.7	100.0	%	
Dry	11	20.0	%	8.1	20.7	%		1	3.0	%	1.0	4.0	%		—	—	%	—	—	%	
Total	55	100.0	%	39.1	100.0	%		33	100.0	%	25.3	100.0	%		38	100.0	%	33.7	100.0	%	
Total Productive	651																				