LINN ENERGY, LLC
Form 10-K
February 27, 2014

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

Form 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2013
.. TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 000-51719

LINN ENERGY, LLC
(Exact name of registrant as specified in its charter)

Delaware	65-1177591
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
600 Travis, Suite 5100 Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code
(281) 840-4000
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Units Representing Limited Liability Company Interests	The NASDAQ Global Select Market

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $6.6 billion on June 30, 2013, based on $33.18 per unit, the last reported sales price of the units on the NASDAQ Global Select Market on such date.

As of January 31, 2014, there were 331,287,217 units outstanding.

Documents Incorporated By Reference:
Certain information called for in Items 10, 11, 12, 13 and 14 of Part III are incorporated by reference from the registrant's definitive proxy statement for the annual meeting of unitholders to be held on April 22, 2014.

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Glossary of Terms

As commonly used in the oil and natural gas industry and as used in this Annual Report on Form 10-K, the following terms have the following meanings:

Basin. A large area with a relatively thick accumulation of sedimentary rocks.

Bbl. One stock tank barrel or 42 United States ("U.S.") gallons liquid volume.

Bcf. One billion cubic feet.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Btu. One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 degrees to 59.5 degrees Fahrenheit.

Development well. A well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive.

Diatomite. A sedimentary rock composed primarily of siliceous, diatom shells.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

Enhanced oil recovery. A technique for increasing the amount of crude oil that can be extracted from an oil field.

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.

Formation. A stratum of rock that is recognizable from adjacent strata consisting mainly of a certain type of rock or combination of rock types with thickness that may range from less than two feet to hundreds of feet.

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

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

MBbls/d. MBbls per day.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMBoe. One million barrels of oil equivalent, determined using a ratio of one Bbl of oil, condensate or natural gas liquids to six Mcf.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

MMcf/d. MMcf per day.

MMcfe. One million cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

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MMcfe/d. MMcfe per day.
MMMBtu. One billion British thermal units.
Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.
NGL. Natural gas liquids, which are the hydrocarbon liquids contained within natural gas.
Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.
Proved developed reserves. Reserves that can be expected to be recovered 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. Additional reserves expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.
Proved reserves. Reserves that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. 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.
Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.
Proved undeveloped reserves or PUDs. Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. 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. Undrilled locations can be 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. Estimates for proved undeveloped reserves are not attributed 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.
Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.
Reservoir. A porous and permeable underground formation containing a natural accumulation of economically productive natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reserves.
Royalty interest. An interest that entitles the owner of such interest to a share of the mineral production from a property or to a share of the proceeds there from. It does not contain the rights and obligations of operating the property and normally does not bear any of the costs of exploration, development and operation of the property.
Spacing. The number of wells which conservation laws allow to be drilled on a given area of land.
Standardized measure of discounted future net cash flows. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the regulations of the Securities and Exchange Commission ("SEC"), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses or depreciation, depletion and amortization; discounted using an annual discount rate of 10%.

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Tcfe. One trillion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.
Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, natural gas and NGL regardless of whether such acreage contains proved reserves.
Unproved reserves. Reserves that are considered less certain to be recovered than proved reserves. Unproved reserves may be further sub-classified to denote progressively increasing uncertainty of recoverability and include probable reserves and possible reserves.
Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.
Workover. Maintenance on a producing well to restore or increase production.
Zone. A stratigraphic interval containing one or more reservoirs.

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Part I

Item 1. Business

This Annual Report on Form 10-K contains forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see "Forward-Looking Statements" included at the end of this Item 1. "Business" and see also Item 1A. "Risk Factors."

References

When referring to Linn Energy, LLC ("LINN Energy" or the "Company"), the intent is to refer to LINN Energy and its consolidated subsidiaries as a whole or on an individual basis, depending on the context in which the statements are made.

The reference to a "Note" herein refers to the accompanying Notes to Consolidated Financial Statements contained in Item 8. "Financial Statements and Supplementary Data."

Overview

LINN Energy's mission is to acquire, develop and maximize cash flow from a growing portfolio of long-life oil and natural gas assets. LINN Energy is an independent oil and natural gas company that began operations in March 2003 and completed its initial public offering ("IPO") in January 2006. The Company's properties are located in the United States ("U.S."), in the Rockies, the Mid-Continent, the Hugoton Basin, California, the Permian Basin, Michigan, Illinois and east Texas.

Proved reserves at December 31, 2013, were approximately 6,403 Bcfe, of which approximately 34% were oil, 47% were natural gas and 19% were natural gas liquids ("NGL"). Approximately 68% were classified as proved developed, with a total standardized measure of discounted future net cash flows of approximately $11.9 billion. At December 31, 2013, the Company operated 14,594 or 74% of its 19,810 gross productive wells and had an average proved reserve-life index of approximately 16 years, based on the December 31, 2013, reserve reports and fourth quarter 2013 annualized production, including full fourth quarter 2013 Berry Petroleum Company ("Berry") production.

Strategy

The Company's primary goal is to provide stability and growth of distributions for the long-term benefit of its unitholders. The following is a summary of the key elements of the Company's business strategy:

- grow through acquisition of long-life, high quality properties;
- efficiently operate and develop acquired properties; and
- reduce cash flow volatility through hedging.

The Company's business strategy is discussed in more detail below.

Grow Through Acquisition of Long-Life, High Quality Properties

The Company's acquisition program targets oil and natural gas properties that it believes will be financially accretive and offer stable, long-life, high quality production with relatively predictable decline curves, as well as lower-risk development opportunities. The Company evaluates acquisitions based on rate of return, field cash flow, operational efficiency, reserve life, development costs and decline profile. As part of this strategy, the Company continually seeks to optimize its asset portfolio, which may include the divestiture of noncore assets. This allows the Company to redeploy capital into projects to develop lower-risk, long-life and low-decline properties that are better suited to its business strategy.

Since January 1, 2009, the Company has completed 35 acquisitions of working and royalty interests in oil and natural gas properties and related gathering and pipeline assets. Total acquired proved reserves at the date of acquisition were approximately 4.7 Tcfe with acquisition costs of approximately $1.97 per Mcfe. Estimates of proved reserves at the date of acquisition were primarily prepared by the independent engineering firm, DeGolyer and MacNaughton. The Company finances acquisitions with equity or a combination of funds from equity and debt offerings, bank borrowings and net cash provided by operating activities. See Note 2 for additional details about the Company's acquisitions.

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Efficiently Operate and Develop Acquired Properties

The Company has organized the operation of its acquired properties into defined operating regions to minimize operating costs and maximize production and capital efficiency. The Company maintains a large inventory of drilling and optimization projects within each region to achieve organic growth from its capital development program. The Company generally seeks to be the operator of its properties so that it can develop drilling programs and optimization projects that not only replace production, but add value through reserve and production growth and future operational synergies. The development program is focused on lower-risk, repeatable drilling opportunities to maintain and/or grow net cash provided by operating activities. Many of the Company's wells are completed in multiple producing zones with commingled production and long economic lives. In addition, the Company seeks to deliver attractive financial returns by leveraging its experienced workforce and scalable infrastructure. For 2014, the Company estimates its total capital expenditures, excluding acquisitions, will be approximately $1.6 billion, including approximately $1.55 billion related to its oil and natural gas capital program and approximately $35 million related to its plant and pipeline capital. This estimate is under continuous review and is subject to ongoing adjustments. The Company expects to fund these capital expenditures primarily with net cash provided by operating activities and bank borrowings.

Reduce Cash Flow Volatility Through Hedging

An important part of the Company's business strategy includes hedging a significant portion of its forecasted production to reduce exposure to fluctuations in the prices of oil and natural gas and provide long-term cash flow predictability to manage its business, service debt and pay distributions. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits the Company's ability to effectively hedge its NGL production. As a result, currently, the Company directly hedges only its oil and natural gas production. By removing a significant portion of the price volatility associated with future production, the Company expects to mitigate, but not eliminate, the potential effects of variability in net cash provided by operating activities due to fluctuations in commodity prices.

The Company enters into commodity hedging transactions primarily in the form of swap contracts that are designed to provide a fixed price and, from time to time, put options that are designed to provide a fixed price floor with the opportunity for upside. The Company enters into these transactions with respect to a portion of its projected production to provide an economic hedge of the risk related to the future commodity prices received. The Company does not enter into derivative contracts for trading purposes.

The Company maintains a substantial portion of its hedges in the form of swap contracts. From time to time, the Company has chosen to purchase put option contracts primarily in connection with acquisition activity to hedge volumes in excess of those already hedged with swap contracts. Put options require the payment of a premium, which the Company pays in cash at the time of execution and no additional amounts are payable in the future under the contracts. The appropriate level of production to be hedged is an ongoing consideration and is based on a variety of factors, including current and future expected commodity market prices, cost and availability of put option contracts, the level of acquisition activity and the Company's overall risk profile, including leverage and size and scale considerations. As a result, the appropriate percentage of production volumes to be hedged may change over time.

In certain historical periods, the Company paid an incremental premium to increase the fixed price floors on existing put options because the Company typically hedges multiple years in advance and in some cases commodity prices had increased significantly beyond the initial hedge prices. As a result, the Company determined that the existing put option strike prices did not provide reasonable downside protection in the context of the current market.

As part of the acquisition of Berry (see Note 2), the Company assumed certain derivative contracts that Berry had entered into prior to the acquisition date, including swap contracts, collars and three-way collars. Collar contracts specify floor and ceiling prices to be received as compared to floating market prices. Three-way collar contracts combine a short put (the lower price), a long put (the middle price) and a short call (the higher price) to provide a higher ceiling price as compared to a regular collar and limit downside risk to the market price plus the difference between the middle price and the lower price if the market price drops below the lower price.

For additional details about the Company's commodity derivatives, see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk." See also Note 7 and Note 8.

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In addition, the Company may from time to time enter into derivative contracts in the form of interest rate swaps to minimize the effects of fluctuations in interest rates. Currently, the Company has no outstanding interest rate swaps.

Recent Developments

Acquisitions

On December 16, 2013, the Company completed the previously-announced transactions contemplated by the merger agreement between the Company, LinnCo, LLC ("LinnCo"), an affiliate of LINN Energy, and Berry under which LinnCo acquired all of the outstanding common shares of Berry and the contribution agreement between LinnCo and the Company, under which LinnCo contributed Berry to the Company in exchange for LINN Energy units. Under the merger agreement, as amended, Berry's shareholders received 1.68 LinnCo common shares for each Berry common share they owned, totaling 93,756,674 LinnCo common shares. Under the contribution agreement, LinnCo contributed Berry to LINN Energy in exchange for 93,756,674 newly issued LINN Energy units, after which Berry became an indirect wholly owned subsidiary of LINN Energy. The transaction has a preliminary value of approximately $4.6 billion, including the assumption of approximately $2.3 billion of Berry's debt and net of cash acquired of approximately $451 million.

The consolidated financial statements and financial and operational results of the Company reflect the combined entities since the acquisition date. The Company plans to file the stand-alone financial statements of Berry with the Securities and Exchange Commission ("SEC") at a later date.

Berry's principal reserves and producing properties are located in California (San Joaquin Valley Basin and Los Angeles Basin), Texas (Permian Basin and east Texas), Utah (Uinta Basin) and Colorado (Piceance Basin). The acquisition included approximately 1,408 Bcfe of proved reserves as of the acquisition date. At December 31, 2013, Berry had approximately 3,400 gross productive wells and more than 200,000 net acres.

On October 31, 2013, the Company completed the acquisition of certain oil and natural gas properties located in the Permian Basin for total consideration of approximately $528 million. The acquisition included approximately 175 Bcfe of proved reserves as of the acquisition date.

During 2013, the Company also completed other smaller acquisitions of oil and natural gas properties located in its various operating regions. The Company, in the aggregate, paid approximately $40 million in total consideration for these properties.

Proved reserves as of the acquisition date for all of the above referenced acquisitions were estimated using the average oil and natural gas prices during the preceding 12-month period, determined as an unweighted average of the first-day-of-the-month prices for each month. Estimates of proved reserves as of the acquisition date for all of the above referenced acquisitions as well as estimates of proved reserves at December 31, 2013, were prepared by the independent engineering firm, DeGolyer and MacNaughton.

The Company regularly engages in discussions with potential sellers regarding acquisition opportunities. Such acquisition efforts may involve its participation in auction processes, as well as situations in which the Company believes it is the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts can involve assets that, if acquired, would have a material effect on the Company's financial condition and results of operations.

Divestiture

On May 31, 2013, the Company, through one of its wholly owned subsidiaries, together with the Company's partners, Panther Energy, LLC and Red Willow Mid-Continent, LLC, completed the sale of its interests in certain oil and natural gas properties located in the Mid-Continent region ("Panther Operated Cleveland Properties") to Midstates Petroleum Company, Inc. Proceeds received for the Company's portion of its interests in the properties were approximately $218 million, net of costs to sell of approximately $2 million. The Company used the net proceeds from the sale to repay borrowings under the LINN Credit Facility, as defined below.

Distributions

On January 2, 2014, the Company's Board of Directors declared a cash distribution of $0.725 per unit with respect to the fourth quarter of 2013, to be paid in three equal monthly installments of $0.2416 per unit. The first monthly distribution with respect to the fourth quarter of 2013, totaling approximately $80 million, was paid on January 16,

2014, to unitholders of

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record as of the close of business on January 13, 2014, and the second monthly distribution, totaling approximately $80 million, was paid on February 13, 2014, to unitholders of record as of the close of business on February 10, 2014.

Operating Regions

The Company's properties, including those acquired in the Berry acquisition, are located in seven operating regions in the U.S.:

- Rockies, which includes properties located in Wyoming (Green River Basin and Powder River Basin), Utah (Uinta Basin), North Dakota (Williston Basin) and Colorado (Piceance Basin);
- Mid-Continent, which includes properties in Oklahoma, Louisiana and the eastern portion of the Texas Panhandle (including the Granite Wash and Cleveland horizontal plays);
- Hugoton Basin, which includes properties located primarily in Kansas and the Shallow Texas Panhandle;
- California, which includes the San Joaquin Valley Basin and the Los Angeles Basin;
- Permian Basin, which includes areas in west Texas and southeast New Mexico;
- Michigan/Illinois, which includes the Antrim Shale formation in the northern part of Michigan and oil properties in southern Illinois; and
- East Texas, which includes properties located in east Texas.

Rockies

The Rockies region consists of properties located in Wyoming (Green River Basin and Powder River Basin), northeastern Utah (Uinta Basin), North Dakota (Bakken and Three Forks formations in the Williston Basin) and northwestern Colorado (Piceance Basin). Properties located in the Uinta and Piceance basins were acquired in the Berry acquisition. Wells in this diverse region produce from both oil and natural gas reservoirs at depths ranging from 1,000 feet to over 13,000 feet. The Company's properties in the Jonah Field located in the Green River Basin of southwest Wyoming produce from the Lance and Mesaverde formations at depths ranging from 8,000 feet to 13,500 feet. The Company's properties in the Powder River Basin consist of a CO2 flood operated by Anadarko Petroleum Corporation in the Salt Creek Field. The Company's properties in the Uinta Basin produce at depths ranging from 5,000 feet to 7,500 feet. The Company's nonoperated properties in the Williston Basin produce at depths ranging from 9,000 feet to 12,000 feet and its properties in the Piceance Basin produce at depths ranging from 7,500 feet to 9,500 feet.

Rockies proved reserves represented approximately 28% of total proved reserves at December 31, 2013, of which 46% were classified as proved developed. This region produced 187 MMcfe/d or 23% of the Company's 2013 average daily production. During 2013, the Company invested approximately $306 million to drill in this region. During 2014, the Company anticipates spending approximately 38% of its total oil and natural gas capital budget for development activities in the Rockies region.

Mid-Continent

The Mid-Continent region includes properties located in Oklahoma, Louisiana and the eastern portion of the Texas Panhandle (including the Granite Wash and Cleveland horizontal plays). Wells in this diverse region produce from both oil and natural gas reservoirs at depths ranging from 1,500 feet to over 18,000 feet. The Granite Wash formation and other shallower producing horizons are currently being developed using horizontal drilling and multi-stage stimulations. In the northern Texas Panhandle and extending into western Oklahoma, the Cleveland formation is being developed as a horizontal oil play. Elsewhere in Oklahoma, several producing formations are being targeted using similar horizontal drilling and completion technologies. The majority of wells in this region are mature, low-decline oil and natural gas wells.

Mid-Continent proved reserves represented approximately 20% of total proved reserves at December 31, 2013, of which 77% were classified as proved developed. This region produced 330 MMcfe/d or 40% of the Company's 2013 average daily production. During 2013, the Company invested approximately $439 million to drill in this region. During 2014, the Company anticipates spending approximately 16% of its total oil and natural gas capital budget for development activities in the Mid-Continent region.

To more efficiently transport its natural gas in the Mid-Continent region to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 325 miles of pipeline and associated compression and

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metering facilities. In connection with the horizontal development activities in the Granite Wash formation, the Company continues to expand this gathering system which connects to numerous natural gas processing facilities in the region.

Hugoton Basin

The Hugoton Basin is a large oil and natural gas producing area located in the central portion of the Texas Panhandle extending into southwestern Kansas. The Company's Texas properties in the basin primarily produce from the Brown Dolomite formation at depths of approximately 3,200 feet and its Kansas properties primarily produce from the Council Grove and Chase formations at depths ranging from 2,500 feet to 3,000 feet. Hugoton Basin proved reserves represented approximately 18% of total proved reserves at December 31, 2013, of which 82% were classified as proved developed. This region produced 143 MMcfe/d or 17% of the Company's 2013 average daily production. During 2013, the Company invested approximately $35 million to drill in this region. During 2014, the Company anticipates spending approximately 3% of its total oil and natural gas capital budget for development activities in the Hugoton Basin region.

To more efficiently transport its natural gas in the Texas Panhandle to market, the Company owns and operates a network of natural gas gathering systems comprised of approximately 665 miles of pipeline and associated compression and metering facilities that connect to numerous sales outlets in the area. The Company also owns and operates the Jayhawk natural gas processing plant in southwestern Kansas with a capacity of approximately 450 MMcfe/d, allowing it to extract maximum value from the liquids-rich natural gas produced in the area. The Company's production in the area is delivered to the plant via a system of approximately 2,100 miles of pipeline and related facilities operated by the Company, of which approximately 250 miles of pipeline are owned by the Company.

California

The California region consists of the Midway-Sunset Field, Diatomite, McKittrick and Poso Creek properties in the San Joaquin Valley Basin and the Brea Olinda Field and Placerita Field in the Los Angeles Basin. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation to the deeper Miocene formation at depths ranging from 1,000 feet to 7,500 feet. The properties in the Midway-Sunset Field, Diatomite, McKittrick, Placerita Field and Poso Creek were acquired in the Berry acquisition and produce using thermal enhanced oil recovery methods at depths ranging from 800 feet to 2,000 feet. California proved reserves represented approximately 14% of total proved reserves at December 31, 2013, of which 80% were classified as proved developed. This region produced 19 MMcfe/d or 2% of the Company's 2013 average daily production. During 2013, the Company invested approximately $33 million to drill in this region. During 2014, the Company anticipates spending approximately 16% of its total oil and natural gas capital budget for development activities in the California region.

Permian Basin

The Permian Basin is one of the largest and most prolific oil and natural gas basins in the U.S. The Company's properties are located in west Texas and southeast New Mexico and primarily produce at depths ranging from 2,000 feet to 12,000 feet. The Wolfberry trend is located in the north central portion of the basin where the Company has been actively drilling vertical oil wells since 2010. The Company also produces oil and natural gas from mature, low-decline wells including several waterflood properties located across the basin. Certain of the properties located in Texas were acquired in the Berry acquisition. Permian Basin proved reserves represented approximately 13% of total proved reserves at December 31, 2013, of which 51% were classified as proved developed. Recent industry activity has begun focusing on Wolfcamp horizontal drilling in the vicinity of the Company's properties. The Company had no proved reserves booked for Wolfcamp horizontal wells at December 31, 2013. This region produced 87 MMcfe/d or 11% of the Company's 2013 average daily production. During 2013, the Company invested approximately $218 million to drill in this region. During 2014, the Company anticipates spending approximately 25% of its total oil and natural gas capital budget for development activities in the Permian Basin region, primarily in the Wolfberry trend.

Michigan/Illinois

The Michigan/Illinois region includes properties producing from the Antrim Shale formation in the northern part of Michigan and oil properties in southern Illinois. These wells produce at depths ranging from 600 feet to 4,000 feet. Michigan/Illinois proved reserves represented approximately 4% of total proved reserves at December 31, 2013, of

which 97% were classified as proved developed. This region produced 34 MMcfe/d or 4% of the Company's 2013 average daily production. During 2014, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the Michigan/Illinois region.

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East Texas

The East Texas region consists of properties located in east Texas and primarily produces natural gas from the Cotton Valley formation and the Haynesville/Bossier Shale at depths ranging from 7,000 to 13,500 feet. Certain of the properties located in the Cotton Valley formation and all of the Haynesville/Bossier Shale properties were acquired in the Berry acquisition. Proved reserves for these mature, low-decline producing properties, all of which are proved developed, represented approximately 3% of total proved reserves at December 31, 2013. This region produced 22 MMcfe/d or 3% of the Company's 2013 average daily production. During 2014, the Company anticipates spending approximately 1% of its total oil and natural gas capital budget for development activities in the East Texas region.

Drilling and Acreage

The following sets forth the wells drilled during the periods indicated ("gross" refers to the total wells in which the Company had a working interest and "net" refers to gross wells multiplied by the Company's working interest):

	Year Ended December 31,		
	2013	2012	2011
Gross wells:			
Productive	557	436	292
Dry	2	4	2
	559	440	294
Net development wells:			
Productive	304		