Diamondback Energy, Inc.
Form 10-K
February 19, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ý ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2013
OR
¨ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934
Commission File Number 001-35700

Diamondback Energy, Inc.
(Exact Name of Registrant As Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	45-4502447 (IRS Employer Identification Number)
500 West Texas, Suite 1200 Midland, Texas (Address of Principal Executive Offices)	79701 (Zip Code)

(Registrant Telephone Number, Including Area Code): (432) 221-7400

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	The NASDAQ Stock Market LLC

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 ý 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 ý
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 ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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	ý	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 Exchange Act). Yes ¨ No ý

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2013 was approximately $800,108,000.

As of February 3, 2014, 47,106,216 shares of the registrant’s common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Diamondback Energy, Inc.’s Proxy Statement for the 2014 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used throughout this report:

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

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

Bbls/d. Bbls per day.

BOE. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

BOE/d. BOE per day.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

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

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding and development costs. Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.

Fracturing. The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.

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

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle with a specified interval.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

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

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

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Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.
Net revenue interest. An owner’s interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.
PDP. Proved developed producing.
Play. A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
PUD. Proved undeveloped.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.
Stratigraphic play. An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.
Structural play. An oil or natural gas formation contained within an area created by earth movements that deform or rupture (such as folding or faulting) rock strata.
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 and natural gas regardless of whether such acreage contains proved reserves.
Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this report that express a belief, expectation or intention, or 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, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “contin “predict,” “potential,” “project” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this Annual Report on Form 10–K could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy;
- exploration and development drilling prospects, inventories, projects and programs;
- oil and natural gas reserves;
- identified drilling locations;
- ability to obtain permits and governmental approvals;
- technology;
- financial strategy;
- realized oil and natural gas prices;
- production;
- lease operating expenses, general and administrative costs and finding and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

All forward-looking statements speak only as of the date of this report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

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PART I

Diamondback Energy, Inc., or Diamondback, was incorporated in Delaware on December 30, 2011, and did not conduct any material business operations until October 11, 2012 when Diamondback merged with its parent entity, Diamondback Energy LLC, with Diamondback continuing as the surviving entity. Prior to the merger, Diamondback Energy LLC was a holding company and did not conduct any material business operations other than its ownership of Diamondback's common stock and the membership interests in Windsor Permian LLC, or Windsor Permian. As a result of the merger, Windsor Permian became a wholly-owned subsidiary of Diamondback. Also on October 11, 2012, Wexford Capital LP, or Wexford, our equity sponsor, caused all of the outstanding equity interests in Windsor UT LLC, or Windsor UT, to be contributed to Windsor Permian prior to the merger in a transaction we refer to as the "Windsor UT Contribution." In this Annual Report on Form 10-K, the combined consolidated historical financial information, operational data and reserve information for Diamondback present the assets and liabilities of Diamondback and its subsidiaries, including Windsor UT, as if they were combined for all periods presented. Although the financial and other information is reported on a combined consolidated basis, such presentation is not necessarily indicative of the results that would have been obtained if Diamondback had owned and operated Windsor UT from its inception. In this Annual Report on Form 10-K, we refer to Diamondback, together with its consolidated subsidiaries, as "we," "us," "our," or "the Company". This report includes certain terms commonly used in the oil and gas industry, which are defined above in the "Glossary of Oil and Natural Gas Terms."

ITEM 1. BUSINESS

Overview

We are an independent oil and natural gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. This basin, which is one of the major producing basins in the United States, is characterized by an extensive production history, a favorable operating environment, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators.

We began operations in December 2007 with our acquisition of 4,174 net acres with production at the time of acquisition of approximately 800 BOE/d from 34 gross (16.8 net) wells in the Permian Basin. Subsequently, we acquired approximately 61,764 additional net acres, which brought our total net acreage position in the Permian Basin to 65,938 net acres at December 31, 2013. We are the operator of approximately 99% of this acreage. In addition, we own mineral interests underlying approximately 15,000 gross (12,500 net) acres in Midland County, Texas, and we are the operator of approximately 50% of the acreage associated with these mineral interests. As of December 31, 2013, we had drilled 270 gross (243 net) wells, and participated in an additional 22 gross (nine net) non-operated wells, in the Permian Basin. Of these 292 gross (252 net) wells, 277 were completed as producing wells and 15 were in various stages of completion. In 2013, we acquired working interests in 49 gross (40 net) producing wells. In the aggregate, as of December 31, 2013, we held interests in 351 gross (306 net) producing wells in the Permian Basin. Nine gross (eight net) wells have been plugged and abandoned or converted to service wells. We also hold royalty interests in 81 wells in which we have no working interest. As discussed in more detail below under "–Pending Acquisition," we recently entered into agreements to acquire approximately 6,450 gross (2,825 net) leasehold acres in Martin County, Texas.

Our activities are primarily focused on the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations, which we refer to collectively as the Wolfberry play. The Wolfberry play is characterized by high oil and liquids rich natural gas, multiple vertical and horizontal target horizons, extensive production history, long-lived reserves and high drilling success rates. The Wolfberry play is a modification and extension of the Spraberry play, the majority of which is designated in the Spraberry Trend area field. According to the U.S. Energy Information Administration, the Spraberry trend area ranked as the second largest oilfield in the United States, based on 2009 reserves.

As of December 31, 2013, our estimated proved oil and natural gas reserves were 63,586 MBOE based on a reserve report prepared by Ryder Scott Company, L.P., or Ryder Scott, our independent reserve engineers. Of these reserves, approximately 45% are classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate are from 206 vertical gross (151 net) well locations on 40-acre spacing and 43 gross (31 net) horizontal well locations. As of December 31, 2013, these proved reserves were approximately 67% oil, 17% natural gas liquids and 16% natural gas.

Based on our evaluation of applicable geologic and engineering data as of December 31, 2013, we had 848 identified potential vertical drilling locations on 40-acre spacing, an additional 1,128 identified potential vertical drilling locations based on 20-acre downspacing and we had also identified 1,430 potential horizontal drilling locations in multiple horizons on our acreage. We intend to continue to grow our reserves and production through development drilling, exploitation and exploration activities on this multi-year project inventory of identified potential drilling locations and through additional acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves. The gross estimated ultimate recoveries, or EURs, from our future PUD vertical wells on 40-acre spacing, as estimated by Ryder Scott as of December 31, 2013, range from 109 MBOE per well, consisting of 83 MBbls of oil and 156 MMcf of natural gas to 150 MBOE per well, consisting of 114 MBbls of oil and 214 MMcf of natural gas, with an average EUR per well of 128 MBOE, consisting of 94 MBbls of oil and 204 MMcf of natural gas. We also intend to continue to refine our drilling pattern and completion techniques in an effort to increase our average EUR per well from vertical wells drilled on 40-acre spacing. We currently anticipate a reduction of approximately 20% in our EURs from vertical wells drilled on 20-acre spacing.

Horizontal Wells. In 2012, we began testing the horizontal well potential of our acreage. Our first horizontal well was the Janey 16H in Upton County and was drilled in the Wolfcamp B interval. We are the operator of this well with a 100% working interest. Our second horizontal well was the Kemmer 4209H well in Midland County also drilled in the Wolfcamp B interval. It is a non-operated well in which we own a 47% working interest. Since the initial two wells, through December 31, 2013, we have drilled 41 horizontal wells as operator and participated in six wells as non-operator, including two in which we own only a minor wellbore interest. Of these 49 total horizontal wells (including our two initial wells), 44 are in the Wolfcamp B interval, two are in the Clearfork zone, two are in the Spraberry zone and one is in the Cline zone. Thirty-seven of the 49 wells were completed and producing as of December 31, 2013 and the other 12 are in various stages of completion. The table below presents certain data regarding our producing horizontal wells (excluding the two non-operated wells in which we hold only a minor wellbore interest).

County/Zone	Number of Producing Wells	Lateral Length	Peak 24-HR IP (BOE/d)	30-Day IP Rate (BOE/d)	% Oil
Midland County Wolfcamp B[(a)]	16	5,591’	899	650	88%
Upton County Wolfcamp B[(b)]	15	6,453’	880	566	83%
Andrews County Wolfcamp B	1	4,051’	613	440	83%
Midland County Spraberry	2	5,042’	905	732	84%
Andrews County Clearfork	1	7,540’	611	390	82%

(a) The 30-day initial production, or IP, rate and percentage of oil for Midland County Wolfcamp B is based on 13 wells for which there is sufficient production history.

(b) The 30-day IP rate and percentage of oil for Upton County Wolfcamp B is based on 13 wells for which there is sufficient production history.

The production results from the wells in Midland and Upton Counties, along with geoscience and engineering data that we have gathered and analyzed, and published results by other operators, give us confidence that our acreage in Midland and Upton Counties is prospective in the Wolfcamp B interval. Additionally, we believe the results of our operated wells in Andrews County in the Wolfcamp B and the Clearfork intervals significantly reduces the hydrocarbon risks of our acreage in the vicinity of those wells.

Pending Acquisition

We have entered into definitive purchase agreements dated February 14, 2014 with unrelated third party sellers to acquire additional leasehold interests in Martin County, Texas, in the Permian Basin, for an aggregate purchase price of approximately $174.0 million, subject to certain adjustments. This transaction includes 6,450 gross (2,825 net) acres with a 43.8% working interest (75% net revenue interest) and net production of approximately 1,300 BOE/d (approximately 75% oil) during the first two weeks of February 2014 based on information reported by the operator, from 147 gross (63 net) producing vertical wells. Net proved reserves, based on our internal estimates as of December

31, 2013, were approximately 4,185 MBOE. Our estimate of proved reserves is based on our analysis of production data provided by the sellers, as well as available geologic and other data, and we may revise our estimates following ownership of these properties. We believe the acreage is prospective for horizontal drilling in the Wolfcamp B, Lower Spraberry, Middle Spraberry, Wolfcamp A, Cline and Clearfork horizons, and have identified 42 potential horizontal drilling locations in each of the Wolfcamp B and Lower Spraberry horizons based on 160 acre spacing per well (or six across a section) and an aggregate of 112 potential horizontal drilling

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locations in the Middle Spraberry, Wolfcamp A, Cline and Clearfork intervals, based on 240 acre spacing per well (or four across a section). Under the terms of the existing joint operating agreement, we have made offers to the owners of the remaining 56.2% of the working interests to acquire their interests in the acreage. If all such owners were to sell their interests to us, the aggregate purchase price would be approximately $397.2 million. We intend to finance the acquisition, subject to market conditions and other factors, with a combination of borrowings under our revolving credit facility and the issuance of new debt and equity securities. We will become the operator of this acreage if and when two or more working interest holders with more than 50% of the working interest appoint us as the successor operator. The acquisition is scheduled to close by the end of February 2014, however the transaction remains subject to completion of due diligence and satisfaction of other customary closing conditions, and there can be no assurance that the transaction will be completed.

Our Business Strategy

Our business strategy is to continue to profitably grow our business through the following:

- Grow production and reserves by developing our oil-rich resource base. We intend to actively drill and develop our acreage base in an effort to maximize its value and resource potential. Through the conversion of our undeveloped reserves to developed reserves, we will seek to increase our production, reserves and cash flow while generating favorable returns on invested capital. As of December 31, 2013, we had 1,430 identified potential horizontal drilling locations, and 848 identified potential vertical drilling locations on our acreage in the Permian Basin based on 40-acre spacing and an additional 1,128 vertical locations based on 20-acre downspacing. We were operating a one vertical rig drilling program as of December 31, 2013, as we increase our focus on horizontal wells.
- Focus on increasing hydrocarbon recovery through horizontal drilling and increased well density. We believe there are opportunities to target various intervals in the Wolfberry play with horizontal wells. Our initial horizontal focus has been on the Wolfcamp B interval in Midland and Upton Counties. Our first two horizontal wells were completed in 2012 and had lateral lengths of less than 4,000 feet. Subsequently, we have drilled 41 horizontal wells as operator and have participated in six additional horizontal wells as a non-operator, including two in which we own only a minor wellbore interest. Of these 49 total horizontal wells (including our two initial wells), 44 are in the Wolfcamp B interval, two are in the Clearfork zone, two are in the Spraberry zone, and one is in the Cline zone. These wells have lateral lengths ranging from approximately 4,000 feet to 10,300 feet. In the future, we expect that our optimal average lateral lengths will be in the range of 6,000 feet to 7,500 feet, although the actual length will vary depending on the layout of our acreage and other factors. We expect that longer lateral lengths will result in higher per well recoveries and lower development costs per BOE. During the year ended December 31, 2013, we were able to drill our horizontal wells with approximately 7,500 foot lateral lengths to total depth, or TD, in an average of 18 days and we drilled an approximately 10,000 foot lateral well in 17 days. Our future horizontal drilling program is designed to further capture the upside potential that may exist on our properties. We also believe our horizontal drilling program may significantly increase our recoveries per section as compared to drilling vertical wells alone. Horizontal drilling may also be economical in areas where vertical drilling is currently not economical or logistically viable. In addition, we believe increased well density opportunities may exist across our acreage base. We closely monitor industry trends with respect to higher well density, which could increase the recovery factor per section and enhance returns since infrastructure is typically in place. We were using four horizontal drilling rigs as of December 31, 2013, and currently intend to add a fifth horizontal rig in the second quarter of 2014.
- Leverage our experience operating in the Permian Basin. Our executive team, which has an average of over 25 years of industry experience per person and significant experience in the Permian Basin, intends to continue to seek ways to maximize hydrocarbon recovery by refining and enhancing our drilling and completion techniques. Our focus on efficient drilling and completion techniques is an important part of the continuous drilling program we have planned for our significant inventory of identified potential drilling locations. We believe that the experience of our executive team in deviated and horizontal drilling and completions should help reduce the execution risk normally associated with these complex well paths. In addition, our completion techniques are continually evolving as we evaluate hydraulic fracturing practices that may potentially increase recovery and reduce completion costs. Our executive team regularly evaluates our operating results against those of other operators in the area in an effort to benchmark our performance against the best performing operators and evaluate and adopt best practices.

- Enhance returns through our low cost development strategy of resource conversion, capital allocation and continued improvements in operational and cost efficiencies. In the current commodity price environment, our oil and liquids rich asset base provides attractive returns. Our acreage position in the Wolfberry play is generally in contiguous blocks which allows us to develop this acreage efficiently

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with a “manufacturing” strategy that takes advantage of economies of scale and uses centralized production and fluid handling facilities. We are the operator of approximately 99% of our acreage. This operational control allows us to more efficiently manage the pace of development activities and the gathering and marketing of our production and control operating costs and technical applications, including horizontal development. Our average 86% working interest in our acreage allows us to realize the majority of the benefits of these activities and cost efficiencies.

- Pursue strategic acquisitions with exceptional resource potential. We have a proven history of acquiring leasehold positions in the Permian Basin that have substantial oil-weighted resource potential and can achieve attractive returns on invested capital. Our executive team, with its extensive experience in the Permian Basin, has what we believe is a competitive advantage in identifying acquisition targets and a proven ability to evaluate resource potential. We regularly review acquisition opportunities and intend to pursue acquisitions that meet our strategic and financial targets. During the year ended December 31, 2013, we acquired mineral interests underlying approximately 15,000 gross (12,500 net) acres in Midland County, Texas and acquired approximately 13,900 additional gross (11,150 net) leasehold acres in Martin County, Texas and Dawson County, Texas. We have entered into agreements dated February 14, 2014 to acquire 6,450 gross (2,825 net) acres in Martin County, Texas. See “–Pending Acquisition” above for more information regarding the acquisition. We intend to continue to pursue acquisitions that meet our strategic and financial targets.
- Maintain financial flexibility. We seek to maintain a conservative financial position. Upon completion of our initial public offering in October 2012, we used a portion of the net proceeds from the offering to repay the entire balance outstanding under our revolving credit facility. On November 1, 2013, our credit agreement was amended and restated, resulting in an increase to the borrowing base under our revolving credit facility to $225.0 million, of which $215.0 million was available for borrowing as of December 31, 2013.

Our Strengths

We believe that the following strengths will help us achieve our business goals:

- Oil rich resource base in one of North America’s leading resource plays. All of our leasehold acreage is located in one of the most prolific oil plays in North America, the Permian Basin in West Texas. The majority of our current properties are well positioned in the core of the Wolfberry play. We believe that our historical vertical development success will be complemented with horizontal drilling locations that could ultimately translate into an increased recovery factor on a per section basis. Our production for the year ended December 31, 2013 was approximately 76% oil, 13% natural gas liquids and 11% natural gas. As of December 31, 2013, our estimated net proved reserves were comprised of approximately 67% oil and 17% natural gas liquids, which allows us to benefit from the currently more favorable pricing of oil and natural gas liquids as compared to natural gas.
- Multi-year drilling inventory in one of North America’s leading oil resource plays. We have identified a multi-year inventory of potential drilling locations for our oil-weighted reserves that we believe provides attractive growth and return opportunities. As of December 31, 2013, we had 848 identified potential vertical drilling locations based on 40-acre spacing and an additional 1,128 identified potential vertical drilling locations based on 20-acre downspacing. We also believe that there are a significant number of horizontal locations that could be drilled on our acreage. Based on our initial results and those of other operators in the area to date, combined with our interpretation of various geologic and engineering data, we have identified 1,430 potential horizontal locations on our existing acreage with an average lateral length of approximately 6,270 feet, with the actual length depending on lease geometry and other considerations. These locations exist across most of our acreage blocks and in multiple horizons. Of the 1,430 existing locations, 604 are in the Wolfcamp B horizon or the Lower Spraberry horizon, with the remaining locations in either the Wolfcamp A, Clearfork, Wolfcamp C or Cline horizons. Our current horizontal location count is based on 660 foot spacing between wells in the Wolfcamp B horizon in Midland County where we operate and own mineral interests, and 880 foot spacing elsewhere in the Wolfcamp B horizon in Midland County and other counties. In the Lower and Middle Spraberry, well counts are based on 880 foot spacing in Midland County and 1,320 foot spacing in other counties. For all other zones and counties, our well counts are based on 1,320 foot spacing. The ultimate inter-well spacing may be closer than these distances, which would result in a higher location count. The gross two-stream estimated EURs from our future PUD horizontal wells, as estimated by Ryder Scott as of December 31, 2013, range from 374 MBOE per well, consisting of 274 MBbls of oil and 604 MMcf of natural gas, to 847 MBOE

per well, consisting of 623 MBbls of oil and 1,342 MMcf of natural gas, for wells ranging in lateral length from approximately 5,000 feet to approximately 10,000 feet, in intervals including the Clearfork, Middle Spraberry, Lower Spraberry,

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and Wolfcamp B. Ryder Scott has estimated gross EURs of 638 MBOE for our Wolfcamp B wells in Andrews and Midland Counties, which constitute 51% of our remaining PUD horizontal wells, and 604 MBOE for our eastern Upton County Wolfcamp B wells, which constitute 19% of our remaining PUD horizontal wells, in each case based on 7,500 foot lateral lengths. In addition, we have approximately 182 square miles of proprietary 3-D seismic data covering our acreage. This data facilitates the evaluation of our existing drilling inventory and provides insight into future development activity, including horizontal drilling opportunities and strategic leasehold acquisitions.

- Experienced, incentivized and proven management team. Our executive team has an average of over 25 years of industry experience per person, most of which is focused on resource play development. This team has a proven track record of executing on multi-rig development drilling programs and extensive experience in the Permian Basin. In addition, our executive team has significant experience with both drilling and completing horizontal wells as well as horizontal well reservoir and geologic expertise, which will be of strategic importance as we expand our horizontal drilling activity. Prior to joining us, our Chief Executive Officer held management positions at Apache Corporation, Laredo Petroleum Holdings, Inc. and Burlington Resources.
- Favorable and stable operating environment. We have focused our drilling and development operations in the Permian Basin, one of the oldest hydrocarbon basins in the United States, with a long and well-established production history and developed infrastructure. With approximately 380,000 wells drilled in the Permian Basin since the 1940s, we believe that the geological and regulatory environment is more stable and predictable, and that we are faced with less operational risks, in the Permian Basin as compared to emerging hydrocarbon basins.
- High degree of operational control. We are the operator of approximately 99% of our Permian Basin acreage. This operating control allows us to better execute on our strategies of enhancing returns through operational and cost efficiencies and increasing ultimate hydrocarbon recovery by seeking to continually improve our drilling techniques, completion methodologies and reservoir evaluation processes. Additionally, as the operator of substantially all of our acreage, we retain the ability to adjust our capital expenditure program based on commodity price outlooks. This operating control also enables us to obtain data needed for efficient exploration of horizontal prospects.
- Financial flexibility to fund expansion. We have a conservative balance sheet. We will seek to maintain financial flexibility to allow us to actively develop our drilling, exploitation and exploration activities in the Wolfberry play and maximize the present value of our oil-weighted resource potential. As of December 31, 2013, we had $10.0 million of borrowings outstanding under our revolving credit facility and $215.0 million of available borrowing capacity.

Our Properties

Location and Land

We acquired approximately 4,174 net acres in West Texas (near Midland) in the Permian Basin on December 20, 2007, with an effective date of November 1, 2007, from ExL Petroleum, LP, Ambrose Energy I, Ltd. and certain other sellers. Subsequently, we acquired approximately 61,764 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 65,938 net acres at December 31, 2013. We are the operator of approximately 99% of this Permian Basin acreage. In addition, we own mineral interests underlying approximately 15,000 gross (12,500 net) acres in Midland County, Texas, and we are the operator of approximately 50% of the acreage associated with these mineral interests. Since our initial acquisition in the Permian Basin through December 31, 2013, we drilled or participated in the drilling of 291 gross (251 net) wells on our leasehold acreage in this area, primarily targeting the Wolfberry play. The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is considered one of the major producing basins in the United States.

Area History

Our proved reserves are located in the Permian Basin of West Texas, in particular in the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations. The Spraberry play was initiated with production from several new field discoveries in the late 1940s and early 1950s. It was eventually recognized that a regional productive trend was present, as fields were extended and coalesced over a broad area in the central Midland Basin. Development in the Spraberry play was sporadic over the next several decades due to typically low productive rate wells, with economics being dependent on oil prices and drilling costs.

The Wolfcamp formation is a long-established reservoir in West Texas, first found in the 1950s as wells aiming for deeper targets occasionally intersected slump blocks or debris flows with good reservoir properties.

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Exploration using 2-D seismic data located additional fields, but it was not until the use of 3-D seismic data in the 1990s that the greater extent of the Wolfcamp formation was revealed. The additional potential of the shales within this formation as reservoir rather than just source rocks was not recognized until very recently.

During the late 1990s, Atlantic Richfield Company, or Arco, began a drilling program targeting the base of the Spraberry formation at 10,000 feet, with an additional 200 to 300 feet drilled to produce from the upper portion of the Wolfcamp formation. Henry Petroleum, a private firm, owned interests in the Pegasus field in Midland and Upton counties. While drilling in the same area as the Arco project, Henry Petroleum decided to drill completely through the Wolfcamp section. Henry Petroleum mapped the trend and began acquiring acreage and drilling wells using multiple slick-water fracturing treatments across the entire Wolfcamp interval. In 2005, former members of Henry Petroleum's Wolfcamp team formed their own private company, ExL Petroleum, and began replicating Henry Petroleum's program. After ExL had drilled 32 productive Wolfcamp/Spraberry wells through late 2007, they monetized a portion of their acreage position, which led to the acquisition that enabled us to begin our participation in this play. Recent advancements in enhanced recovery techniques and horizontal drilling continue to make this play attractive to the oil and gas industry. By mid-2010, approximately half of the rigs active in the Permian Basin were drilling wells in the Wolfberry play. As of December 31, 2013, we held interests in 351 gross (306 net) producing wells.

Geology

The Permian Basin formed as an area of rapid Mississippian-Pennsylvanian subsidence in the foreland of the Ouachita fold belt. It is one of the largest sedimentary basins in the U.S., and has oil and gas production from several reservoirs from Permian through Ordovician in age. The term "Wolfberry" was coined initially to indicate commingled production from the Permian Spraberry, Dean and Wolfcamp formations. In this report, we refer to the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations collectively as the Wolfberry play. The Wolfberry play of the Midland Basin lies in the area where the historically productive Spraberry trend geographically overlaps the productive area of the emerging Wolfcamp play. The Spraberry was deposited as turbidites in a deep water submarine fan environment, while the Wolfcamp reservoirs consist of debris-flow and grain-flow sediments, which were also deposited in a submarine fan setting. The best carbonate reservoirs within the Wolfcamp are generally found in proximity to the Central Basin Platform, while the shale reservoirs within the Wolfcamp thicken basinward away from the Central Basin Platform. Both the Spraberry and Wolfcamp contain organic-rich mudstones and shales which, when buried to sufficient depth for maturation, became the source of the hydrocarbons found in the reservoirs.

The Wolfberry play can be generally characterized as a combination of low-permeability clastic, carbonate and shale reservoirs which are hydrocarbon-charged and are economic due to the overall thickness of the section (more than 3,000 feet) and application of enhanced stimulation (fracking) techniques. The Wolfberry is an unconventional "basin-centered oil" resource play, in the sense that there is no regional downdip oil/water contact.

Several shale intervals within the Wolfcamp formation are currently being evaluated for horizontal development potential, and initial drilling to explore these intervals commenced in 2012. The shales exhibit micro-darcy permeabilities which result in relatively small drainage areas and recovery factors. Because of this, we believe the horizontal exploitation of these reservoirs will supplement, and not replace, our vertical development program.

There are also productive carbonate and shale intervals within the shallower Permian Clearfork formation. Two shale intervals within the Clearfork formation are currently being evaluated for potential horizontal development. Below the Wolfcamp formation lie the Pennsylvanian Strawn and Atoka formations. Although difficult to predict, there are conventional pay intervals that develop locally within these formations which, when present, can add significant reserves.

Debris flows within the Spraberry and Wolfcamp carbonates have been observed on 3-D seismic surveys. Initial tests have confirmed the presence of enhanced reservoir. Additionally, structural closures have been mapped and are being evaluated for drilling to test deeper targets. Our extensive geophysical database, which includes approximately 182 square miles of proprietary 3-D seismic data, will be used to enhance grading of future locations.

Production Status

During the year ended December 31, 2013, net production from our Permian Basin acreage was 2,672,244 BOE, or an average of 7,321 BOE/d, of which approximately 76% was oil, 13% was natural gas liquids and 11% was natural gas.

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Facilities

Our land oil and gas processing facilities are typical of those found in the Permian Basin. Our facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Future Activity

During 2014, we expect to drill an estimated 65 to 75 gross (52 to 60 net) horizontal wells and 20 to 25 gross (16 to 20 net) vertical wells on our acreage. We currently estimate that our capital expenditures for 2014 will be between $425.0 million and $475.0 million, which includes costs for infrastructure and non-operated wells but does not include the cost of any land acquisitions, including the pending acquisition. During the year ended December 31, 2013, we drilled 38 gross (37 net) horizontal wells and 39 gross (33 net) vertical wells and participated in the drilling of four gross (two net) non-operated wells in the Permian Basin. During the year ended December 31, 2013, our aggregate capital expenditures for drilling and oil gas infrastructure were $297.7 million, and we spent an additional $640.0 million for leasehold and mineral rights acquisitions.

Oil and Natural Gas Data

Proved Reserves

SEC Rule-Making Activity

In December 2008, the Securities and Exchange Commission, or SEC, released its final rule for "Modernization of Oil and Gas Reporting." These rules require disclosure of oil and gas proved reserves by significant geographic area, using the arithmetic 12-month average beginning-of-the-month price for the year, as opposed to year-end prices as had previously been required, unless contractual arrangements designate the price to be used. Other significant amendments included the following:

- Disclosure of unproved reserves: probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved undeveloped reserve guidelines: reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.
- Reserves estimation using new technologies: reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserves personnel and estimation process: additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.
- Non-traditional resources: the definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective December 31, 2009, as required by the SEC.

Evaluation and Review of Reserves

Our historical reserve estimates as of December 31, 2013, 2012 and 2011 were prepared by Ryder Scott, with respect to our assets in the Permian Basin.

Ryder Scott is an independent petroleum engineering firm. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott is a third-party engineering firm and does not own an interest in any of our properties and is not employed by us on a contingent basis.

Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2013 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second

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determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. The proved reserves for our properties were estimated by performance methods, analogy or a combination of both methods. Approximately 85% of the proved producing reserves attributable to producing wells were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of available historical production and pressure data. The remaining 15% of the proved producing reserves were estimated by analogy, or a combination of performance and analogy methods. The analogy method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. All proved developed non-producing and undeveloped reserves were estimated by the analogy method.
To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Permian Basin. Our internal technical team members met with our independent reserve engineers periodically during the period covered by the reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Our Vice President—Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. Our Vice President—Reservoir Engineering is a petroleum engineer with over 30 years of reservoir and operations experience and our geoscience staff has an average of approximately 26 years of industry experience per person. Our technical staff uses historical information for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by our Vice President—Reservoir Engineering or under his direct supervision;
- review by our Vice President—Reservoir Engineering of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- direct reporting responsibilities by our Vice President—Reservoir Engineering to our Chief Executive Officer;
- verification of property ownership by our land department; and
- no employee’s compensation is tied to the amount of reserves booked.

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2013, 2012 and 2011, based on the reserve report prepared by Ryder Scott. Each reserve report has been prepared in accordance with the rules and regulations of the SEC. All of our proved reserves included in the reserve reports are located in the continental United States.

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	Year Ended December 31,		
	2013	2012	2011
Estimated proved developed reserves:			
Oil (Bbls)	19,789,965	7,189,367	3,949,099
Natural gas (Mcf)	31,428,756	12,864,941	5,285,945
Natural gas liquids (Bbls)	4,973,493	2,999,440	1,263,710
Total (BOE)	30,001,584	12,332,964	6,093,800
Estimated proved undeveloped reserves:			
Oil (Bbls)	22,810,887	19,007,492	14,151,337
Natural gas (Mcf)	30,250,740	21,705,207	15,265,522
Natural gas liquids (Bbls)	5,732,231	5,251,989	3,785,849
Total (BOE)	33,584,908	27,877,016	20,481,440
Estimated Net Proved Reserves:			
Oil (Bbls)	42,600,852	26,196,859	18,100,436
Natural gas (Mcf)	61,679,496	34,570,148	20,551,467
Natural gas liquids (Bbls)	10,705,724	8,251,429	5,049,559
Total (BOE)[1]	63,586,492	40,209,979	26,575,240
Percent proved developed	47.2 %	30.7 %	22.9 %

(1) Estimates of reserves as of December 31, 2013, 2012 and 2011 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2013, 2012 and 2011, respectively, in accordance with SEC guidelines applicable to reserves estimates as of the end of such periods. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

The foregoing reserves are all located within the continental United States. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See Item 1A.“Risk Factors.” We have not filed any estimates of total, proved net oil or natural gas reserves with any federal authority or agency other than the SEC.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2013, our proved undeveloped reserves totaled 22,811 MBbls of oil, 30,251 MMcf of natural gas and 5,732 MBbls of natural gas liquids, for a total of 33,585 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Changes in PUDs that occurred during 2013 were primarily due to:

- additions of 15,928 MBOE attributable to extensions resulting from strategic drilling of wells by us to delineate our acreage position;
- the conversion of approximately 4,733 MBOE attributable to PUDs into proved developed reserves;
- negative revisions of approximately 9,493 MBOE in PUDs, 7.933 MBOE of which was due to downgrading 92 vertical locations that were booked as PUDs to probable in accordance with the SEC five year PUD rule; and

- purchases of reserves in place of 4,006 MBOE.

Costs incurred relating to the development of PUDs were approximately $76.6 million during 2013. Estimated future development costs relating to the development of PUDs are projected to be approximately $201 million in 2014, $166 million in 2015, $109 million in 2016 and $26 million in 2017. Since our current executive team assumed management control in 2011, our average drilling costs and drilling times have been reduced. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years.

All of our PUD drilling locations are scheduled to be drilled prior to the end of 2018.

As of December 31, 2013, 2% of our total proved reserves were classified as proved developed non-producing.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding our net production of oil, natural gas and natural gas liquids, all of which is from the Permian Basin in West Texas, and certain price and cost information for each of the periods indicated:

	Historical		
	Year Ended December 31,		
	2013	2012	2011
Production Data:			
Oil (Bbls)	2,022,749	756,286	449,434
Natural gas (Mcf)	1,730,497	833,516	413,640
Natural gas liquids (Bbl)	361,079	183,114	86,815
Combined volumes (BOE)	2,672,244	1,078,320	605,189
Daily combined volumes (BOE/d)	7,321	&#16	