Diamondback Energy, Inc.
Form 424B4
August 15, 2013
Filed Pursuant to Rule 424(b)(4)
Registration Statement No. 333-190462

PROSPECTUS
4,000,000 Shares

Diamondback Energy, Inc.
Common Stock

We are offering 4,000,000 shares of our common stock.

Our common stock is listed on the NASDAQ Global Select Market under the symbol "FANG." The last reported sales price of our common stock on the NASDAQ Global Select Market on August 14, 2013 was $40.45 per share.

We have granted the underwriters an option to purchase up to 600,000 additional shares of our common stock at the public offering price less underwriting discounts and commissions.

We are an "emerging growth company" under applicable Securities and Exchange Commission rules and are subject to reduced public company reporting requirements. Investing in our common stock involves risks. See "Risk Factors" beginning on page 15.

	Price to Public	Underwriting Discounts and Commissions (1)	Proceeds to Diamondback
Per Share	$40.25	$1.61	$38.64
Total	$161,000,000	$6,440,000	$154,560,000

(1) We refer you to "Underwriting" beginning on page 89 of this prospectus for additional information regarding underwriting compensation.

Delivery of the shares of common stock will be made on or about August 20, 2013.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

Credit Suisse

Wells Fargo Securities
Raymond James
Tudor, Pickering, Holt & Co.

Simmons & Company International
Suntrust Robinson Humphrey
Capital One Southcoast
Scotiabank / Howard Weil
Sterne Agee
IBERIA Capital Partners L.L.C.
Brean Capital
Miller Tabak
Sidoti & Company, LLC
Wunderlich Securities

The date of this prospectus is August 14, 2013.

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ABOUT THIS PROSPECTUS

You should rely only on the information contained or incorporated by reference in this prospectus. We have not, and the underwriters have not, authorized any other person to provide you with information different from that contained in this prospectus. If anyone provides you with different or inconsistent information, you should not rely on it. You should read the entire prospectus, as well as the documents incorporated by reference herein that are described under "Where You Can Find More Information" and "Information Incorporated by Reference." We and the underwriters are only offering to sell, and only seeking offers to buy, shares of our common stock in jurisdictions where offers and sales are permitted.

The information contained in this prospectus or in any document incorporated in this prospectus is accurate and complete only as of the date hereof or thereof, respectively, regardless of the time of delivery of this prospectus or of any sale of our common stock by us or the underwriters. Our business, financial condition, results of operations and prospects may have changed since that date.

Industry and Market Data

This prospectus includes industry data and forecasts that we obtained from internal company surveys, publicly available information and industry publications and surveys. Our internal research and forecasts are based on management's understanding of industry conditions, and such information has not been verified by independent sources. Industry publications and surveys generally state that the information contained therein has been obtained from sources believed to be reliable.

Unless the context otherwise requires, the information in this prospectus assumes that the underwriters will not exercise their option to purchase additional shares.

PROSPECTUS SUMMARY

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 Diamondback O&G LLC, or Diamondback O&G (formerly known as 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 prospectus, 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 such subsidiaries from their inception. In this prospectus, we refer to Diamondback, together with its consolidated subsidiaries, as "we," "us," "our" or "the Company." This prospectus includes certain terms commonly used in the oil and natural gas industry, which are defined elsewhere in this prospectus in the "Glossary of Oil and Natural Gas Terms."

Diamondback Energy, Inc.

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 49,861 additional net acres, which brought our total net acreage position in the Permian Basin to 54,035 net acres at June 30, 2013. We are the operator of approximately 99% of this acreage. As of June 30, 2013, we had drilled 230 gross (209 net) wells, and participated in an additional 19 gross (eight net) non-operated wells, in the Permian Basin. Of these 249 gross (216 net) wells, 240 were completed as producing wells and nine were in various stages of completion. In the aggregate, as of June 30, 2013, we held interests in 274 gross (242 net) producing wells in the Permian Basin. As discussed in more detail under "—Recent Developments—Pending Acquisitions," we have entered into agreements to acquire approximately 11,150 additional net acres in the Permian Basin.

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 ranks as the second largest oilfield in the United States, based on 2009 reserves.

As of December 31, 2012, our estimated proved oil and natural gas reserves were 40,210 MBOE based on a reserve report prepared by Ryder Scott Company, L.P., or Ryder Scott, our independent reserve engineer. Of these reserves, approximately 29.5% are classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate are from 306 vertical gross well locations on 40-acre spacing and four gross horizontal well locations. As of December 31, 2012, these proved reserves were approximately 65% oil, 21% natural gas liquids and 14% natural gas.

We have 867 identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data as of June 30, 2013, and we have an additional 1,128 identified potential vertical drilling locations based on 20-acre downspacing. We have also identified 862 potential horizontal drilling locations in multiple horizons on our acreage. We intend 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 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, range from 102 MBOE per well, consisting of 46 MBbls of oil, 151 MMcf of natural gas and 31 MBbls of natural gas liquids, to 158 MBOE per well, consisting of 112 MBbls

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of oil, 114 MMcf of natural gas and 27 MBbls of natural gas liquids, with an average EUR per well of 133 MBOE, consisting of 91 MBbls of oil, 101 MMcf of natural gas and 25 MBbls of natural gas liquids. 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.

The following table summarizes certain operating information of our properties. The information is as of June 30, 2013 except as otherwise noted.

			Identified Potential Drilling Locations[(1)]		2013 Budget			Estimated Net Proved Reserves at December 31, 2012		Average Daily
Basin	Net Acreage[(2)]	Average Working Interest	Gross	Net	Gross Wells[(3)]	Net Wells[(3)]	Capex (In millions)	MBOE	% Developed	Production (BOE/d)[(4)]
Permian	54,035	88 %	1,729	1,472	74	65	$290.0 - $320.0	40,210	30.7	7,164

(1) Reflects 867 gross and (809 net) identified potential vertical drilling locations on 40-acre spacing, and 862 gross (663 net) identified potential horizontal drilling locations ranging in length from 4,500 feet to 9,500 feet in various horizons from the Clearfork to the Cline based on our evaluation of applicable geologic and engineering data. Some of these horizontal drilling locations require pooling acreage with other operators. We have an additional 1,128 gross (1,031 net) identified potential vertical drilling locations based on 20-acre downspacing. The drilling locations on which we actually drill wells will ultimately depend on the availability of capital, regulatory approvals, oil and natural gas prices, costs, actual drilling results and other factors.

(2) Does not give effect to our pending acquisitions of approximately 11,150 additional net acres. See "—Recent Developments—Pending Acquisitions."

(3) Includes 38 gross (33 net) operated vertical wells, 33 gross (30 net) operated horizontal wells, two gross (one net) non-operated vertical wells and one gross (one net) non-operated horizontal well.

(4) During June 2013.

We currently estimate our 2013 capital budget for drilling and infrastructure will be approximately $290.0 million to $320.0 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. We intend to allocate these expenditures approximately as follows:

- $267.6 million for the drilling and completion of operated wells, of which approximately 65% is allocated to horizontal wells;
- $9.0 million for our participation in the drilling and completion of non-operated wells; and
- $25.0 million for the construction of infrastructure to support production, including investments in water disposal infrastructure and gathering line projects.

The amount and timing of these capital expenditures are largely discretionary and within our control. We could choose to defer a portion of these planned 2013 capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners.

During the six months ended June 30, 2013, our aggregate capital expenditures for drilling and infrastructure were $112.1 million, and we spent an additional $6.2 million for leasehold acquisitions.

We were using three horizontal drilling rigs as of June 30, 2013. Due to the success of our horizontal drilling program to date, we expect to add a fourth horizontal drilling rig during 2013 which will enable us to drill and complete more wells than we originally contemplated for our 2013 drilling program. As a result of our expected increase in our horizontal drilling activity, and assuming the additional wells we complete produce at rates similar to those of our existing wells, we currently anticipate that our full-year 2013 production will be at or above the high end of our previously announced production guidance, with expected production increases weighted towards the second half of 2013. Our ability to achieve our production guidance is forward-looking and subject to numerous assumptions and risks. See “Risk Factors—Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment and adversely affect our business, financial condition or results of operations” on page 28 of this prospectus.

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Our Business Strategy

Our business strategy is to increase stockholder value 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 June 30, 2013, we had 867 identified potential vertical drilling locations and 862 identified potential horizontal 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 June 30, 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 or are currently drilling 17 horizontal wells as operator and have participated in one additional horizontal well as a non-operator, 19 of which are Wolfcamp B wells and one of which is a Clearfork well. These wells have had lateral lengths ranging from approximately 4,300 feet to 10,300 feet. In the future, we expect that our optimal average lateral lengths will be in the range of 7,500 feet to 8,000 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 first six months of 2013, we were able to drill our horizontal wells with approximately 7,500 foot lateral lengths to total depth in an average of 21 days and we recently drilled a 10,353 foot lateral well in 19 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 three horizontal drilling rigs as of June 30, 2013, and currently intend to add a fourth horizontal rig in the fourth quarter of 2013, and are currently contemplating adding one or two additional horizontal drilling rigs in 2014.
- Leverage our experience operating in the Permian Basin. Our executive team, which has an average of approximately 24 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. The time to reach total depth, or TD, for our vertical Wolfberry wells decreased from an average of 18 days during the second quarter of 2011 to an average of 14 days during the period from April 2012 through August 2012 to an average of 11 days during the fourth quarter of 2012 to an average of eight days during the second quarter of 2013, with three of our recent vertical wells reaching TD in less than seven days. Our focus on efficient drilling and completion techniques, and the reduction in time to reach TD, 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 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 88% 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

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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. As discussed in more detail under "—Recent Developments—Pending Acquisitions," we have entered into agreements to acquire approximately 11,150 additional net acres in the Permian Basin.

- 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 December 28, 2012, the borrowing base under our revolving credit facility was redetermined, resulting in an increase in our availability to $135.0 million, and it was redetermined again on May 6, 2013, resulting in an increase in availability to $180.0 million. We used a portion of the net proceeds of our May 2013 common stock offering to repay all borrowings outstanding under our revolving credit facility and, as of the date of this prospectus, we have the full $180.0 million of borrowing base availability.

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 six months ended June 30, 2013 was approximately 73% oil, 15% natural gas liquids and 12% natural gas. As of December 31, 2012, our estimated net proved reserves were comprised of approximately 65% oil and 21% 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 June 30, 2013, we had 867 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 862 potential horizontal locations on our acreage. These locations exist across most of our acreage blocks and in multiple horizons. Of the 862 locations, 376 are in the Wolfcamp A horizon or the Wolfcamp B horizon, with the remaining locations in either the Clearfork, Spraberry, Wolfcamp C or Cline horizons. We have assigned horizontal locations to the Lower Spraberry, but have not assigned locations to other intervals within the Spraberry, which we believe may have development potential. Our current horizontal location count is based on 880 foot spacing between wells in the Wolfcamp B horizon in Midland and Upton Counties, and 1,320 foot spacing between wells in all other counties and horizons. The ultimate inter-well spacing may be less than these amounts, which would result in a higher location count. Based on horizontal wells drilled to date, we currently estimate that EURs for our Wolfcamp B horizontal wells will be approximately 550 to 650 MBOE for lateral lengths averaging 7,500 feet. 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 approximately 24 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

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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 the date of this prospectus, we had no borrowings outstanding under our revolving credit facility and available borrowing capacity of $180.0 million. We expect that our borrowing base will be further increased as we increase our reserves.

Recent Developments

Pending Acquisitions. We recently entered into two separate definitive agreements to acquire additional leasehold interests in the Permian Basin for an aggregate purchase price of $165.0 million, subject to certain adjustments. On August 2, 2013, we entered into a purchase and sale agreement in which we agreed to acquire from an unrelated third party certain assets located in northwestern Martin County, Texas, consisting of a 100% working interest (80% net revenue interest) in 4,506 gross and net acres, with 16 gross and net producing vertical wells, an estimated 1,138 MBOE of proved developed reserves (including 167 MBOE attributable to two PDNP wells) as of July 1, 2013 and 457 gross (365 net) BOE per day of production during July 2013. We have identified approximately 96 gross and net horizontal drilling locations on this acreage, of which 32 gross and net locations are located in the Wolfcamp B interval, with lateral lengths expected to range from approximately 5,000 feet to 8,000 feet. In addition, on August 1, 2013, we entered into a purchase and sale agreement in which we agreed to acquire from an unrelated third party certain assets located in southwestern Dawson County, Texas, consisting of a 70% working interest (54% net revenue interest) in 9,390 gross (6,647 net) acres, with 28 gross (18 net) producing vertical wells, an estimated 838 MBOE of proved developed reserves (including 77 MBOE attributable to one PDNP well) as of June 1, 2013 and 777 gross (417 net) BOE per day of production during June 2013. We have identified approximately 156 gross (109 net) potential horizontal drilling locations on this acreage, of which 53 gross (37 net) locations are located in the Wolfcamp B interval, with lateral lengths ranging from approximately 5,000 feet to 9,500 feet. Estimated proved reserves for both acquisitions relate solely to existing vertical wells, are based on management's internal assessment of information provided to us in the course of our due diligence, and have not been verified by us or any independent petroleum engineers. Both acquisitions remain subject to completion of due diligence and satisfaction of other closing conditions and may not be completed. We will be the operator of all of the acreage to be acquired in these acquisitions. We expect to close these acquisitions by the end of September 2013. We intend to fund the purchase price for these acquisitions from cash on hand and the net proceeds from this offering. See "Use of Proceeds" included elsewhere in this prospectus.

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 with a 3,842 foot lateral in the Wolfcamp B interval. We are the operator of this well with a 100% working interest. It was completed in June 2012 and had a peak 24-hour initial production, or IP, rate of 618 BOE/d and a peak consecutive 30-day average initial production rate of 486 BOE/d, of which 86% was oil. Through June 30, 2013, the Janey 16H had produced a total of 61 MBbls of oil and 73 MMcf of natural gas. Our second horizontal well was the Kemmer 4209H in Midland County. It is a non-operated well in which we own a 47% working interest. It was completed in September 2012 in the Wolfcamp B interval with a 3,733 foot lateral. The production as reported to us by the operator was a peak 24-hour initial production rate of 892 BOE/d and a peak consecutive 30-day average initial production rate of 712 BOE/d, of which 85% was oil. Through June 30, 2013, the Kemmer 4209H had produced a total of 63 MBbls of oil and 64 MMcf of natural gas. Based on the decline curve analysis of the current production, we anticipate that the EUR for each of these wells will be in the range of 400 to 500 MBOE.

Subsequent to the Janey 16H and Kemmer 4209H wells, we have drilled or are currently drilling 17 horizontal wells as operator and have participated in one additional horizontal well as a non-operator, all of which are Wolfcamp B wells in various stages of development. The table below presents certain data regarding our horizontal wells.

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Horizontal Wells: Midland County

Well Name	Lateral Length	Number of Frac Stages	Peak 24-HR IP (BOE/d)	Peak 30 Day IP Rate (BOE/d)	% Oil[(a)]
Kemmer 4209H[(b)]	3,733’	15	892	712[(d)]	85%
ST NW 2501H	4,451’	19	1,054	655[(d)]	90%
ST NW 2502H	4,351’	16	651	500[(c)]	88%
Sarah Ann 3812H[(b)]	4,830’	18	892	711[(d)]	88%
ST W 4301H	7,141’	29	1,136	916[(d)]	85%
ST W 701H	7,280’	29	1,042[(d)]	N/A[(e)]	94%
ST W 4302H	7,071’	30	701[(d)]	N/A[(e)]	93%
ST W 706H	7,541’	Currently completing 30 stage frac			

Horizontal Wells: Upton County

Well Name	Lateral Length	Number of Frac Stages	Peak 24-HR IP (BOE/d)	Peak 30 Day IP Rate (BOE/d)	% Oil[(a)]
Janey 16H	3,842’	16	618	486[(c)]	86%
Neal A Unit 8-1H	7,441’	32	871	697[(c)]	87%
Janey 3H	4,411’	19	724	488[(d)]	82%
Neal B Unit 8-2H	6,501’	26	1,134	617[(d)]	73%
Kendra A Unit 1H	7,411’	30	970	677[(d)]	82%
Jacee A Unit 1H	7,541’	30	1,085	632[(d)]	83%
Janey 2H	4,572’	19	930[(d)]	N/A[(e)]	87%
Janey 4H	4,564’	10	880[(d)]	N/A[(e)]	77%
Charlotte A Unit 1H	10,353’	Currently completing 39 stage frac			
Neal C Unit 8 3H	6,851’	Currently completing 15 stage frac			

Horizontal Wells: Andrews County

Well Name	Lateral Length	Number of Frac Stages	Peak 24-HR IP (BOE/d)	Peak 30 Day IP Rate (BOE/d)	% Oil[(a)]
UL III 4-1H	4,051’	Flowback operations underway			
UL Viper 6-1H	7,540’	Well drilled; frac scheduled			

(a) During the period for which the Peak 30 day IP Rate is presented except in the case of the ST W 701H, Janey 2H and Janey 4H wells, which is based on the Peak 24-hour IP rate.
(b) Non-operated.
(c) On gas lift.
(d) On sub pump.
(e) A peak 30 day IP Rate is not available.

In addition, we are currently drilling three additional horizontal wells. The production results from the wells in Midland and Upton Counties, along with geoscience and engineering data that we have gathered and analyzed, give us confidence that our acreage in Midland and Upton Counties is prospective in the Wolfcamp B interval.

Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. You should read carefully the section of this prospectus entitled “Risk Factors” beginning on page 15 for an explanation of these risks before investing in our common stock. In particular, the following considerations may offset our competitive strengths or have a negative effect on our strategy or operating activities, which could cause a decrease in the price of our common stock and a loss of all or part of your investment:

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- Our business is difficult to evaluate because of our limited operating history.
- Difficulties managing the growth of our business may adversely affect our financial condition and results of operations.
- Failure to develop our undeveloped acreage could adversely affect our future cash flow and income.
- Our exploration and development operations require substantial capital that we may be unable to obtain, which could lead to a loss of properties and a decline in our reserves.
- Our future success depends on our ability to find, develop or acquire additional oil and natural gas reserves.
- The volatility of oil and natural gas prices due to factors beyond our control greatly affects our profitability.
- Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.
- Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with a concentration of operations in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.
- We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could limit our access to suitable markets for the oil and natural gas we produce.
- Our operations are subject to various governmental regulations which require compliance that can be burdensome and expensive.
- Any failure by us to comply with applicable environmental laws and regulations, including those relating to hydraulic fracturing, could result in governmental authorities taking actions that adversely affect our operations and financial condition.
- Our operations are subject to operational hazards for which we may not be adequately insured.
- Our failure to successfully identify, complete and integrate future acquisitions of properties or businesses could reduce our earnings and slow our growth.
- Our two largest stockholders control a significant percentage of our common stock and their interests may conflict with yours.

For a discussion of other considerations that could negatively affect us, see "Risk Factors" beginning on page 15 and "Cautionary Note Regarding Forward-Looking Statements" on page 37 of this prospectus.

Our Equity Sponsor

We were formed by our equity sponsor, Wexford Capital LP, or Wexford, which is a Greenwich, Connecticut-based SEC-registered investment advisor with approximately $4.9 billion under management as of December 31, 2012. Wexford has made public and private equity investments in many different sectors and has particular expertise in the energy and natural resources sector. Upon completion of this offering, assuming Wexford or its affiliates make no additional purchases or our common stock, Wexford will beneficially own approximately 25.5% of our common stock (approximately 25.2% if the underwriters' option to purchase additional shares is exercised in full). As a result, Wexford will continue to be able to exercise significant control over all matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. In connection with our initial public offering in October 2012, we entered into an advisory services agreement with Wexford under which Wexford provides us with financial and strategic advisory services related to our business. We are also party to certain other agreements with Wexford and its affiliates. For a description of the advisory services agreement and other agreements with Wexford and its affiliates, see "Related Party Transactions" beginning on page 73 of this prospectus. Although our management believes that the terms of these related party agreements are reasonable, it is possible that we could have negotiated more favorable terms for such transactions with unrelated third parties. The existence of these related party agreements may give Wexford the ability to further influence and maintain control over many matters affecting us.

Our History

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

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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, our equity sponsor, caused all of the outstanding equity interests in Windsor UT to be contributed to Windsor Permian prior to the merger in a transaction we refer to as the "Windsor UT Contribution." The Windsor UT Contribution was treated as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. The operations of Windsor Permian and Windsor UT, as limited liability companies, were not subject to federal income taxes. On the date of the merger, a corresponding "first day" tax expense to net income from continuing operations was recorded to establish a net deferred tax liability for differences between the tax and book basis of Diamondback's assets and liabilities. This charge was $54,142,000. We refer to the historical results of Windsor Permian and Windsor UT prior to October 11, 2012 as our "Predecessors."

Immediately after the merger on October 11, 2012, we acquired from Gulfport Energy Corporation, or Gulfport, all of Gulfport's oil and natural gas interests in the Permian Basin, which we refer to as the "Gulfport properties," in exchange for shares of our common stock and a promissory note, in a transaction we refer to as the "Gulfport transaction." The Gulfport transaction was treated as a business combination accounted for under the acquisition method of accounting with the identifiable assets and liabilities recognized at fair value on the date of transfer. For more information regarding the Gulfport transaction, see "Related Party Transactions—Gulfport Transaction and Investor Rights Agreement" and "Shares Eligible for Future Sale—Registration Rights" beginning on pages 73 and 84, respectively, of this prospectus.

On October 17, 2012, we completed our initial public offering, or IPO, of 14,375,000 shares of common stock, which included 1,875,000 shares of common stock issued pursuant to the over-allotment option exercised by the underwriters. The stock was priced at $17.50 per share and we received net proceeds of approximately $234.1 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

On May 21, 2013, we completed an underwritten public offering of 5,175,000 shares of our common stock, including 675,000 shares issued pursuant to an option to purchase additional shares exercised by the underwriters, which offering we refer to in this prospectus as the "May 2013 offering." The public offering price was $29.25 per share, and we received net proceeds of approximately $144.4 million, after underwriting discounts and commissions and estimated expenses. We used a portion of the net proceeds from the May 2013 offering to repay in full all borrowings outstanding under our revolving credit facility and intend to use the remaining proceeds to fund a portion of our exploration and development activities and for general corporate purposes, which may include leasehold interest and property acquisitions and working capital.

On June 24, 2013, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 6,000,000 shares of our common stock and, on July 5, 2013, the underwriters purchased an additional 869,222 shares of our common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. We refer to this offering by the selling stockholders as the "June 2013 secondary offering." The shares in the June 2013 secondary offering were sold to the public at $34.75 per share, and the selling stockholders received all the net proceeds from the sale of their shares.

Emerging Growth Company

We are, and through December 31, 2013 will remain, an "emerging growth company" within the meaning of the federal securities laws. For as long as we are an emerging growth company, we will not be required to comply with certain requirements that are applicable to other public companies that are not "emerging growth companies" including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, the reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements and the exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved. We intend to take advantage of these reporting exemptions until we are no longer an emerging growth company. For a description of the qualifications and other requirements applicable to emerging growth companies and certain elections that we have made due to our status as an emerging growth company, see "Risk Factors—Risks Related to this Offering and our Common Stock—We are an 'emerging growth company' and we cannot be certain if the reduced disclosure requirements applicable to emerging growth companies will make our common stock less attractive to investors" on page 34 of this prospectus.

Our Offices

Our principal executive offices are located at 500 West Texas, Suite 1225, Midland, Texas, and our telephone number at that address is (432) 221-7400. We also lease additional office space in Midland and in Oklahoma City, Oklahoma. Our website address is www.diamondbackenergy.com. Information contained on our website does not constitute part of this prospectus.

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The Offering

Common stock offered by us	4,000,000 shares (4,600,000 shares if the underwriters' option to purchase additional shares is exercised in full).
Option to purchase additional shares	We have granted the underwriters a 30-day option to purchase up to an aggregate of 600,000 additional shares of our common stock.
Common stock to be outstanding immediately after completion of this offering	46,161,532 shares (46,761,532 shares if the underwriters' option to purchase additional shares is exercised in full).
Use of proceeds	We expect to receive approximately $154.3 million of net proceeds from the sale of common stock in this offering, after deducting underwriting discounts and commissions and estimated offering expenses (or approximately $177.4 million if the underwriters' option to purchase additional shares is exercised in full). Following the closing of this offering, we intend to use the net proceeds to fund our pending acquisitions of additional acreage in the Permian Basin. To the extent the pending acquisitions are not consummated, or the applicable purchase prices are less than we currently estimate, we intend to use any remaining net proceeds from this offering to fund a portion of our exploration and development activities and for general corporate purposes, which may include leasehold interest and property acquisitions and working capital. See "Use of Proceeds" on page 38 of this prospectus.
Dividend policy	We currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future.
NASDAQ Global Select Market symbol	"FANG"
Risk Factors	You should carefully read and consider the information set forth under heading "Risk Factors" beginning on page 15 of this prospectus and all other information set forth in this prospectus before deciding to invest in our common stock.

Except as otherwise indicated, all information contained in this prospectus:

- assumes the underwriters do not exercise their option to purchase additional shares of our common stock; and
- excludes 2,500,000 shares of common stock reserved for issuance under our equity incentive plan, including:
- 245,716 restricted stock units issued to certain employees under the terms of their employment agreements;
- 33,330 restricted stock units issued to our non-employee directors as part of their director compensation; and
- options to purchase 913,000 shares of our common stock granted to certain of our employees.

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Summary Combined Consolidated Historical and Pro Forma Financial Data

The following table sets forth our summary historical combined consolidated financial data as of and for each of the periods indicated. The summary historical combined consolidated financial data as of December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 are derived from our historical audited combined consolidated financial statements incorporated by reference into this prospectus. The summary historical combined consolidated balance sheet data as of December 31, 2010 are derived from our audited consolidated balance sheets of the Predecessors as of that date, which is not included in or incorporated by reference into this prospectus. The consolidated statements of operations data for the six months ended June 30, 2013 and June 30, 2012 and the consolidated balance sheet data at June 30, 2013 are derived from our unaudited consolidated financial statements appearing in our most recent Quarterly Report on Form 10-Q incorporated by reference into this prospectus. The consolidated balance sheet data at June 30, 2012 are derived from our unaudited consolidated financial statements that are not included in or incorporated by reference into this prospectus. The unaudited pro forma financial data give effect to (a) the Gulfport transaction and (b) the distribution by Windsor Permian to its equity holder of its minority equity interests in Bison Drilling and Field Services LLC, or Bison, and Muskie Holdings LLC, or Muskie, as described under the heading “Related Party Transactions” beginning on page 73 of this prospectus, as if these transactions occurred on January 1, 2012. The unaudited pro forma C Corporation financial data presented give effect to income taxes assuming we operated as a taxable corporation since inception for the 2011 and 2010 historical columns and since December 31, 2011 for the 2012 historical and pro forma columns. Operating results for the periods presented below are not necessarily indicative of results that may be expected for any future periods. You should review this information together with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” which is incorporated by reference into this prospectus and “Selected Historical Combined Consolidated Financial Data” and “Unaudited Pro Forma Condensed Consolidated Financial Statement” beginning on pages 41 and 46, respectively, of this prospectus as well as our combined consolidated historical financial statements and their related notes incorporated by reference into this prospectus and the statements of revenues and direct operating expenses of certain property interests of Gulfport and their related notes included elsewhere in this prospectus.

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	Historical		Pro Forma	Historical		
	Six Months Ended June 30,		Year Ended December 31,	Year Ended December 31,		
	2013	2012(1)	2012	2012(2)	2011(1)	2010(1)
Statement of Operations Data:						
Oil and natural gas revenues	$74,303,000	$32,381,000	$97,455,000	$74,962,000	$47,875,000	$26,442,000
Other revenues	—	—	—	—	1,491,000	811,000
Expenses:						
Lease operating expense	11,522,000	6,318,000	23,361,000	16,793,000	10,597,000	4,589,000
Production taxes	3,623,000	1,579,000	4,804,000	3,691,000	2,366,000	1,347,000
Gathering and transportation	380,000	146,000	523,000	424,000	202,000	106,000
Oil and natural gas services	—	—	—	—	1,733,000	811,000
Depreciation, depletion and amortization	25,553,000	10,416,000	34,205,000	26,273,000	15,601,000	8,145,000
General and administrative	5,092,000	2,837,000	10,376,000	10,376,000	3,655,000	3,036,000
Asset retirement obligation accretion expense	88,000	41,000	122,000	98,000	65,000	38,000
Total expenses	46,258,000	21,337,000	73,391,000	57,655,000	34,219,000	18,072,000
Income from operations	28,045,000	11,044,000	24,064,000	17,307,000	15,147,000	9,181,000
Other income (expense):						
Interest income	—	2,000	3,000	3,000	11,000	34,000
Interest expense	(1,020,000)	(2,054,000)	(3,610,000)	(3,610,000)	(2,528,000)	(836,000)
Other income	777,000	1,011,000	2,132,000	2,132,000	—	—
Gain (loss) on derivative instruments	3,029,000	5,165,000	2,617,000	2,617,000	(13,009,000)	(148,000)
Loss from equity investment	—	(67,000)	—	(67,000)	(7,000)	—
Total other income (expense), net	2,786,000	4,057,000	1,142,000	1,075,000	(15,533,000)	(950,000)
Net income (loss) before income taxes	30,831,000	15,101,000	25,206,000	18,382,000	(386,000)	8,231,000
Provision for income taxes	10,964,000	—	54,903,000	54,903,000	—	—
Net income (loss)	$19,867,000	$15,101,000	$(29,697,000)	$(36,521,000)	$(386,000)	$8,231,000
Earnings per common share						
Basic	$0.52					
Diluted	$0.52					
Weighted average common shares outstanding						
Basic	38,237,149					
Diluted	38,476,719					

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	Historical		Pro Forma	Historical		
	Six Months Ended June 30,		Year Ended December 31,	Year Ended December, 31		
	2013	2012[1]	2012	2012[2]	2011[1]	2010[1]
Pro Forma C Corporation Data[3]:						
Net income (loss) before income taxes		$15,101,000	$25,206,000	$18,382,000	$(386,000)	$8,231,000
Pro forma for income taxes		5,384,000	8,973,000	6,553,000	—	—
Pro forma net income (loss)		$9,717,000	$16,233,000	$11,829,000	$(386,000)	$8,231,000
Pro forma earnings per common share						
Basic		$0.66	$0.63 [5]	$0.60 [4]		
Diluted		$0.66	$0.63 [5]	$0.60 [4]		
Pro forma weighted average common shares outstanding						
Basic		14,697,496	25,856,823 [5]	19,720,734 [4]		
Diluted		14,697,496	25,859,863 [5]	19,723,774 [4]		
Selected Cash Flow and Other Financial Data:						
Net income (loss)	$19,867,000	$15,101,000		$(36,521,000)	$(386,000)	$8,231,000
Depreciation, depletion and amortization	25,553,000	10,416,000		26,273,000	16,104,000	8,145,000
Other non-cash items	6,847,000	(4,273,000)		56,390,000	13,845,000	344,000
Change in operating assets and liabilities	(2,469,000)	1,417,000		3,550,000	1,435,000	(11,528,000)
Net cash provided by operating activities	$49,798,000	$22,661,000		$49,692,000	$30,998,000	$5,192,000
Net cash used in investing activities	$(138,675,000)	$(59,616,000)		$(183,078,000)	$(81,108,000)	$(55,236,000)
Net cash provided by financing	$144,417,000	$32,337,000		$152,785,000	$52,950,000	$51,733,000

activities

	As of June 30,		As of December 31,		
	2013	2012[(1)]	2012[(2)]	2011[(1)]	2010[(1)]
Balance sheet data:					
Cash and cash equivalents	$81,898,000	$2,341,000	$26,358,000	$6,959,000	$4,119,000
Other current assets	34,638,000	23,226,000	23,917,000	23,853,000	20,947,000
Oil and gas properties, net – using full cost method of accounting	677,446,000	268,353,000	552,640,000	220,465,000	144,552,000
Other property and equipment, net	3,726,000	1,540,000	1,602,000	684,000	11,059,000
Other assets	931,000	1,998,000	2,184,000	11,617,000	638,000
Total assets	$798,639,000	$297,458,000	$606,701,000	$263,578,000	$181,315,000
Current liabilities	97,487,000	51,897,000	79,232,000	42,298,000	19,070,000
Note payable-long term	121,000	339,000	193,000	—	—
Note payable-credit facility-long term	—	90,000,000	—	85,000,000	44,767,000
Note payable-related party-long term	—	14,110,000	—	—	—
Derivative instruments-long term	—	1,667,000	388,000	6,139,000	1,374,000
Asset retirement obligations	2,324,000	1,221,000	2,125,000	1,104,000	742,000
Deferred income taxes	71,098,000	—	62,695,000	—	—
Member's/stockholders' equity	627,609,000	138,224,000	462,068,000	129,037,000	115,362,000
Total liabilities and member's/stockholders' equity	$798,639,000	$297,458,000	$606,701,000	$263,578,000	$181,315,000

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	Historical		Pro Forma	Historical		
			Year Ended			
	Six Months Ended June 30,		December 31,	Year Ended December, 31		
	2013	2012[1]	2012	2012[2]	2011[1]	2010[1]
Other financial data:						
Adjusted EBITDA[6]	$55,399,000	$22,806,000	$63,003,000	$48,223,000	$31,758,000	$17,398,000

(1) The years ended December 31, 2011 and 2010 and the six months ended June 30, 2012 reflect the combined historical financial data of Windsor Permian LLC and Windsor UT LLC due to the transfer of a business between entities under common control. See Note 1 to our combined consolidated financial statements incorporated by reference into this prospectus.

(2) The year ended December 31, 2012 reflects (a) the combined historical financial data of Windsor Permian LLC and Windsor UT LLC due to the transfer of a business between entities under common control and (b) the results of operations attributable to the acquisition of properties from Gulfport Energy Corporation beginning October 11, 2012, the closing date of the property acquisition. See Note 1 and Note 2 to our combined consolidated financial statements incorporated by reference into this prospectus.

(3) Diamondback was formed as a holding company 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. Diamondback is a C-Corp under the Internal Revenue Code and is subject to income taxes. The Company computed a pro forma income tax provision for 2012 as if the Company and the Predecessors were subject to income taxes since December 31, 2011. For 2011 and 2010 comparative purposes, we have included pro forma financial data to give effect to income taxes assuming the earnings of the Company and the Predecessors had been subject to federal income tax as a subchapter C corporation since inception. If the earnings of the Company and the Predecessors had been subject to federal income tax as a subchapter C corporation since inception, we would have incurred net operating losses for income tax purposes in each period. We would have been in a net deferred tax asset, or DTA, position as a result of such tax losses and would have recorded a valuation allowance to reduce each period's DTA balance to zero. A valuation allowance to reduce each period's DTA would have resulted in an equal and offsetting credit for the respective expenses or an equal and offsetting debit for the respective benefits for income taxes, with the resulting tax expenses for each 2011 and 2010 of zero. The unaudited pro forma data is presented for informational purposes only, and does not purport to project our results of operations for any future period or our financial position as of any future date. The pro forma tax provision has been calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, incorporating permanent differences. See Note 1 to our combined consolidated financial statements incorporated by reference into this prospectus.

(4) The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued upon the merger of Diamondback Energy LLC into Diamondback were outstanding for the entire year. Diluted earnings per share reflects the potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock awards and units were fully vested. During periods in which the Company realizes a net loss, options and restricted stock awards would not be dilutive to net loss per share and conversion into common stock is assumed not to occur. See Note 1 to our combined consolidated financial statements incorporated by reference into this prospectus.

(5) The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued upon the merger of Diamondback Energy LLC into Diamondback and as if the common shares issued to Gulfport upon the closing of the Gulfport transaction were outstanding for the entire year. Diluted earnings per share reflects the potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock awards

and units were fully vested. During periods in which the Company realizes a net loss, options and restricted stock awards would not be dilutive to net loss per share and conversion into common stock is assumed not to occur. See Note 1 to our combined consolidated financial statements for the year ended December 31, 2012 incorporated by reference into this prospectus.

(6) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss), see "Selected Historical Combined Consolidated Financial Data" and "Unaudited Pro Forma Condensed Consolidated Financial Statement" beginning on pages 41 and 46, respectively, of this prospectus.

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Summary Historical Reserve Data

The following table sets forth estimates of our net proved oil and natural gas reserves as of December 31, 2012 and 2011, based on the reserve report prepared by Ryder Scott, and as of December 31, 2010, based on the reserve report prepared by Pinnacle Energy Services, LLC, or Pinnacle. Each reserve report was prepared in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC. You should refer to "Risk Factors," "Business—Oil and Natural Gas Data—Proved Reserves," "Business—Oil and Natural Gas Production Prices and Production Costs—Production and Price History" beginning on pages 15, 56 and 59, respectively, of this prospectus and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our audited consolidated financial statements and notes thereto incorporated by reference into this prospectus in evaluating the material presented below.

	Historical Year Ended December 31,		
	2012	2011	2010
Estimated proved developed reserves:			
Oil (Bbls)	7,189,367	3,949,099	3,371,460
Natural gas (Mcf)	12,864,941	5,285,945	4,336,720
Natural gas liquids (Bbls)	2,999,440	1,263,710	1,126,431
Total (BOE)	12,332,964	6,093,800	5,220,678
Estimated proved undeveloped reserves:			
Oil (Bbls)	19,007,492	14,151,337	16,258,700
Natural gas (Mcf)	21,705,207	15,265,522	18,358,360
Natural gas liquids (Bbls)	5,251,989	3,785,849	4,706,536
Total (BOE)	27,877,016	20,481,440	24,024,963
Estimated Net Proved Reserves:			
Oil (Bbls)	26,196,859	18,100,436	19,630,160
Natural gas (Mcf)	34,570,148	20,551,467	22,695,080
Natural gas liquids (Bbls)	8,251,429	5,049,559	5,832,967
Total (BOE)[(1)]	40,209,979	26,575,240	29,245,641
Percent proved developed	30.7 %	22.9 %	17.9 %

(1) Estimates of reserves as of December 31, 2012, 2011 and 2010 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, 2012, 2011 and 2010, respectively, in accordance with revised SEC guidelines applicable to reserve 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.

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RISK FACTORS

An investment in our common stock involves a high degree of risk. You should carefully consider the following risks and all of the other information contained in or incorporated by reference into this prospectus before deciding to invest in our common stock. Our business, financial condition and results of operations could be materially and adversely affected by any of these risks. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks Related to the Oil and Natural Gas Industry and Our Business

Our business is difficult to evaluate because we have a limited operating history.

Diamondback Energy, Inc. was incorporated in Delaware on December 30, 2011. Prior to October 11, 2012, all of our historical oil and natural gas assets, operations and results described in this prospectus were those of Windsor Permian and Windsor UT which, prior to our initial public offering, were entities controlled by our equity sponsor, Wexford. Immediately prior to the effectiveness of the registration statement relating to our initial public offering, Windsor Permian became our wholly-owned subsidiary and we acquired the oil and natural gas assets of Gulfport located in the Permian Basin in the Gulfport transaction. The oil and natural gas properties described in this prospectus have been acquired by Windsor Permian, Gulfport and Windsor UT since December 2007. As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

As a recently-formed company, growth in accordance with our business plan, if achieved, could place a significant strain on our financial, technical, operational and management resources. As we expand our activities and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and natural gas industry, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

Approximately 83% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

Approximately 83% of our net leasehold acreage is undeveloped, or 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. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Our development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. During the six months ended June 30, 2013 and the year ended December 31, 2012, our total capital expenditures, including expenditures for leasehold acquisitions, drilling and infrastructure, were approximately $118.3 million and $111.8 million, respectively. Our 2013 capital budget for drilling, completion and infrastructure, including investments in water disposal infrastructure and gathering line projects, is currently estimated to be approximately $290.0 million to $320.0 million. To date, we have financed capital expenditures primarily with funding from Wexford, our equity sponsor, borrowings under our revolving credit facility, cash generated by operations and the net proceeds of our public offerings of our common stock. Neither Wexford nor any of its affiliates has made any commitment to provide us additional funding, and you should not assume that any of them will provide any debt or equity funding to us in the future.

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In the near term, we intend to finance our capital expenditures with cash flow from operations, proceeds from the May 2013 offering and this offering and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the volume of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

We cannot assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures in 2013 could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include traditional reserve base borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We cannot assure you that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

If we are unable to fund our capital requirements, we may be required to curtail our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves, or we may be otherwise unable to implement our development plan, complete acquisitions or take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies and related cost savings.

Our success depends on finding, developing or acquiring additional reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. We have made, and expect to make in the future, substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves. We may not have sufficient resources to acquire additional reserves or to undertake exploration, development, production or other replacement activities, such activities may not result in significant additional reserves and we may not have success drilling productive wells at low finding and development costs. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Our failure to successfully identify, complete and integrate pending and future acquisitions of properties or businesses could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently operate, which could result in unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Completed acquisitions could require us to invest further in operational, financial and management information systems and to attract, retain, motivate and effectively manage additional employees. The inability to effectively manage the integration of acquisitions, including our pending acquisitions, could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are

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inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest.

Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in the assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Our project areas, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.

Our project areas are in various stages of development, ranging from project areas with current drilling or production activity to project areas that consist of recently acquired leasehold acreage or that have limited drilling or production history. From inception through June 30, 2013, we drilled a total of 230 gross wells and participated in an additional 19 gross non-operated wells, of which 240 wells were completed as producing wells and nine wells were in various stages of completion. If the wells in the process of being completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected.

Our identified potential drilling locations, which are part of our anticipated future drilling plans, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

As of June 30, 2013, we had 867 gross (809 net) identified potential vertical drilling locations on our existing acreage based on 40-acre spacing and an additional 1,128 gross (1,031 net) identified potential vertical drilling locations based on 20-acre downspacing. We have also identified 862 gross (663 net) potential horizontal drilling locations in multiple horizons on our acreage. As of December 31, 2012, only 306 of our gross identified potential vertical drilling locations and four of these identified potential horizontal drilling locations were attributed to proved reserves. These drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, construction of infrastructure, inclement weather, regulatory changes and approvals, oil and natural gas prices, costs, drilling results and the availability of water. Further, our identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. We cannot predict in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable or whether wells drilled on 20-acre downspacing will produce at the same rates as those on 40-acre spacing. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. While to date we are the operator of or have participated in a total of 20 horizontal wells on our acreage, we cannot assure you that the analogies we draw from available data from these or other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Permian Basin may not be indicative of future or long-term production rates. Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.
Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. As of December 31, 2012, we had leases representing 581 net acres expiring in 2013, 2,157 net acres expiring in 2014, 17,826 net acres expiring in 2015, 6,893 net acres expiring in 2016 and 1,820 net acres expiring in 2017. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. In addition, in order to hold our current leases expiring in 2014 and 2015, we will need to operate at least a four-rig program. We cannot assure you that we will have the liquidity to deploy these rigs in this time frame, or that commodity prices will warrant operating such a drilling program. Any such losses of leases could materially and adversely affect the growth of our asset basis, cash flows and results of operations.
The volatility of oil and natural gas prices due to factors beyond our control greatly affects our profitability.
Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including:

- the domestic and foreign supply of oil and natural gas;
- the level of prices and expectations about future prices of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the price of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of alternative fuels; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, has ranged from a low of $30.28 per barrel, or Bbl, in December 2008 to a high of $145.31 per Bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.82 per million British thermal units, or MMBtu, in April 2012 to a high of $13.31 per MMBtu in July 2008. During 2012, West Texas Intermediate prices ranged from $77.72 to $109.39 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.82 to $3.77 per MMBtu. On July 1, 2013, the West Texas Intermediate posted price for crude oil was $97.94 per Bbl and the Henry Hub spot market price of natural gas was $3.52 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments

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to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development results deteriorate, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties.

We have entered into price swap derivatives and may in the future enter into forward sale contracts or additional price swap derivatives for a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and natural gas.

We use price swap derivatives to reduce price volatility associated with certain of our oil sales. Under these swap contracts, we receive a fixed price per barrel of oil and pay a floating market price per barrel of oil to the counterparty based on New York Mercantile Exchange Light Sweet Crude Oil pricing, Argus Louisiana light sweet pricing or Inter-Continental Exchange pricing. The fixed-price payment and the floating-price payment are offset, resulting in a net amount due to or from the counterparty. For the purpose of locking-in the value of a swap, we enter into counter-swaps from time to time. Under the counter-swap, we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. The counter-swap is effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap.

In December 2007, we placed a swap contract covering 1,680,000 Bbls of crude oil for the period from January 2008 to December 2012 at various fixed prices. In April 2008, we entered into a series of counter-swaps to lock-in the value of certain of these swaps settling 1,188,000 Bbls of crude oil swaps. In June 2009, we entered into an additional series of counter-swaps to lock-in the value of most of the remaining swaps settling 324,000 Bbls of crude oil swaps. Locking in the value of our swaps with counter-swaps, without entering into new swaps, exposes us to commodity price risks on the originally swapped position. As of December 31, 2010 and 2009, all of our swap contracts were locked-in with counter swaps. In October 2011, we placed a swap contract covering 1,000 Bbls per day of crude oil for the period from January 1, 2012 through December 31, 2013 at a fixed price of $78.50 per barrel for 2012 and $80.55 per barrel for 2013. In February 2013, we entered into swap contract at a fixed price of $109.70 per barrel covering 365,000 Bbls of crude oil from May 2013 to April 2014 that will settle against the average of the prompt month Brent Crude futures price. In June 2013, we entered into a swap contract at a fixed price of $100.20 per barrel covering 365,000 Bbls of crude oil from July 2013 to June 2014. Our current goal is to hedge from 40% to 70% of our production. The contracts described above and any future hedging arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. In addition, these arrangements may limit the benefit to us of increases in the price of oil. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposure to credit risk is through receivables from joint interest owners on properties we operate (approximately $7.1 million at June 30, 2013) and receivables from purchasers of our oil and natural gas production (approximately $16.4 million at June 30, 2013). Joint interest receivables arise from billing entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We are generally unable to control which co-owners participate in our wells.

We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. For the six months ended June 30, 2013, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (53%); Shell Trading (US) Company (15%); and Occidental Energy Marketing, Inc. (14%). For the year ended December 31, 2012, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (53%); Occidental Energy Marketing, Inc. (16%); and Andrews Oil Buyers, Inc. (10%). For the years ended December 31, 2011 and 2010, one purchaser, Windsor Midstream LLC, an entity controlled by Wexford, our equity sponsor, accounted for approximately 79% of our revenue in both periods. No other customer accounted for more than 10% of our revenue during these periods. This concentration of customers may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Current economic circumstances may further increase these risks. We do not require our customers to post collateral. The inability or failure of our significant customers or joint working interest owners to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial results.

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Our method of accounting for investments in oil and natural gas properties may result in impairment of asset value.
We account for our oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. We also capitalize direct operating costs for services performed with internally owned drilling and well servicing equipment. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Income from services provided to working interest owners of properties in which we also own an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties. Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $24.44 and $23.70 for the six months ended June 30, 2013 and 2012, respectively. The average depletion rate per barrel equivalent unit of production was $23.90, $25.41 and $17.78 for the years ended December 31, 2012, 2011 and 2010, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties for the six months ended June 30, 2013 and 2012 were $25.2 million and $10.2 million, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties for the years ended December 31, 2012, 2011 and 2010 was $25.8 million, $15.4 million and $7.4 million, respectively.
The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment, exceed the discounted future net revenues of proved oil and natural gas reserves, the excess capitalized costs are charged to expense. Beginning December 31, 2009, we have used the unweighted arithmetic average first day of the month price for oil and natural gas for the 12-month period preceding the calculation date in estimating discounted future net revenues.
No impairment on proved oil and natural gas properties was recorded for the six months ended June 30, 2013 or the years ended December 31, 2012, 2011 and 2010. We may, however, experience ceiling test write downs in the future. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Method of accounting for oil and natural gas properties" incorporated by reference into this prospectus for a more detailed description of our method of accounting.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
Oil and natural gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, ultimate recoveries and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may be incorrect. Our historical estimates of proved reserves and related valuations as of December 31, 2012 and 2011 are based on reports prepared by Ryder Scott, an independent petroleum engineering firm. Our historical estimates of proved reserves and related valuations as of December 31, 2010 are based on a report prepared by Pinnacle, an independent petroleum engineering firm. Ryder Scott and Pinnacle, as applicable, conducted a well-by-well review of all our properties for the periods covered by their respective reserve reports using information provided by us. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing and production. Also, certain assumptions regarding future oil and natural gas prices, production levels and operating and development costs may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of future net cash flows. A substantial portion of our reserve estimates are made without the benefit of a lengthy production history, which are

less reliable than estimates based on a lengthy production history. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and natural gas that we ultimately recover being different from our reserve estimates.

The estimates of reserves as of December 31, 2012, 2011 and 2010 included in this prospectus 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, 2012, 2011 and 2010, respectively, in accordance with the revised SEC guidelines applicable to reserve estimates for such periods. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for unproved undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

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The timing of both our production and our incurrence of costs in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves.

SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 69% of our total estimated proved reserves at December 31, 2012 were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

All of our producing properties are geographically concentrated in the Permian Basin of West Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of crude oil, natural gas or natural gas liquids. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

In addition to the geographic concentration of our producing properties described above, at December 31, 2012, all of our proved reserves were attributable to the Wolfberry play. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of natural gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of natural gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. For the six months ended June 30, 2013, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (53%); Shell Trading (US) Company (15%); and Occidental Energy Marketing, Inc. (14%). For the year ended December 31, 2012, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (53%); Occidental Energy Marketing, Inc. (16%); and Andrews Oil Buyers, Inc. (10%). For the years ended December 31, 2011 and 2010, one purchaser, Windsor Midstream LLC, an entity controlled by Wexford, our equity sponsor, accounted for approximately 79% of our revenue in both periods. No other customer accounted for more than 10% of our revenue during these periods. We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production.

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The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. In addition, we do not have long-term contracts securing the use of our existing rigs, and the operator of those rigs may choose to cease providing services to us. In addition, although we intend to increase the number of rigs we have operating in 2013, we cannot guarantee that we will be able to do so. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. According to the Lower Colorado River Authority, during 2011, Texas experienced the lowest inflows of water of any year in recorded history. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically drill for or produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European debt crisis, the United States mortgage market and a weak real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates further, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our oil, natural gas and natural gas liquids, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

We have incurred losses from operations during certain periods since our inception and may do so in the future.

We incurred a net loss of $36.5 million for the year ended December 31, 2012. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures. The uncertainty and risks described in this prospectus may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from our operating activities in the future.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned exploratory drilling in these plays are subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or

production.
Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore

after completion of the final fracture stimulation stage. The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently we are less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, and/or declines in natural gas and oil prices, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Our oil production is transported from the wellhead to our tank batteries by our gathering system. Our purchasers then transport the oil by truck to a pipeline for transportation. Our natural gas production is generally transported by our gathering lines from the wellhead to an interconnection point with the purchaser. We do not control these trucks and other third party transportation facilities and our access to them may be limited or denied. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would adversely affect our financial condition and results of operations.

Our operations are subject to various governmental laws and regulations which require compliance that can be burdensome and expensive.

Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations, requirements for additional pollution controls and injunctions limiting or prohibiting some or all of our operations. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. See “Business—Regulation” beginning on page 62 of this prospectus for a description of the laws and regulations that affect us.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, program.

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Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and natural gas commissions. The Environmental Protection Agency, or EPA, however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as "Class II" UIC wells. At the same time, the White House Council on Environmental Quality is conducting an administration-wide review of hydraulic fracturing practices and the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress.

On August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules will require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules in 2013 that are likely responsive to some of these requests. For example, on April 12, 2013, the EPA published a proposed amendment extending compliance dates for certain storage vessels. The final revised rules could require modifications to our operations or increase our capital and operating costs without being offset by increased product capture. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013 that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts, the results of which are expected between later in 2013 and 2014.

These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shale formations by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

Several states, including Texas, have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Railroad Commission recently adopted rules and regulations requiring that well operators disclose the list of chemical ingredients subject to the requirements of federal Occupational Safety and Health Act, or OSHA, to state regulators and on a public internet website. We plan to use hydraulic fracturing extensively in connection with the development and production of certain of our oil and natural gas properties and any increased federal, state, local, foreign or international regulation of hydraulic fracturing could reduce the volumes of oil and natural gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the

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environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations are adopted that significantly restrict hydraulic fracturing, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development and production activities. These laws and regulations may, among other things: (i) require us to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, producing and other operations; (ii) regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; (iii) limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; (iv) require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or (v) impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, the risk of accidental and/or unpermitted spills or releases from our operations could expose us to significant liabilities, penalties and other sanctions under applicable laws. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The U.S.

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Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation was signed into law by the President on July 21, 2010. In its rulemaking under the legislation, the Commodities Futures Trading Commission, or CFTC, has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions). The CFTC's final rule was set aside by the U.S. District Court for the District of Columbia on September 28, 2012 and remanded to the CFTC to resolve ambiguity as to whether statutory requirements for such limits to be determined necessary and appropriate were satisfied. As a result, the rule has not yet taken effect, although the CFTC has indicated that it intends to appeal the court's decision and that it believes the Dodd-Frank Act requires it to impose position limits. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions. In addition, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirement to use cleared exchanges, rather than hedging over-the-counter, and the requirements to post margin in connection with hedging activities. While it is not possible at this time to predict when the CFTC will finalize certain other related rules and regulations, the Dodd-Frank Act and related regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, our hedging would become more expensive and we may decide to alter our hedging strategy. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our derivative contracts in existence at that time, and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

The U.S. President's Fiscal Year 2014 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws. These changes include, but are not limited to, (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, (iii) the repeal of the percentage depletion allowance for oil and natural gas properties, (iv) an extension of the amortization period for certain geological and geophysical expenditures and (iv) implementing certain international tax reforms. These proposed changes in the U.S. tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule, which purports to limit emissions of GHGs from motor vehicles manufactured in model years 2012 – 2016, in April 2010 and it became effective in January 2011. A recent rulemaking proposal by the EPA and the Department of Transportation's National

Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017 – 2025. The EPA adopted the stationary source rule, also known as the "Tailoring Rule," in May 2010, and it also became effective in January 2011. The Tailoring Rule establishes new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011.

The EPA has continued to adopt GHG regulations of other industries, such as the March 2012 proposed GHG rule restricting future development of coal-fired power plants. The proposed rule underwent an extended public comment process, which concluded on June 25, 2012. The EPA is also under a legal obligation pursuant to a consent decree with certain environmental groups to issue new source performance standards for refineries. The EPA is also considering additional regulation of greenhouse gases as "air pollutants." As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility. In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry. Currently, while we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

In addition, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938, or the NGA, exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission, or FERC. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish whether a pipeline performs a gathering function and therefore is exempt from FERC's jurisdiction under the NGA. However, the distinction between FERC—regulated transmission services and federally unregulated gathering services is a fact-based determination. The classification of facilities as unregulated gathering is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress, which could cause our revenues to decline and operating expenses to increase and may materially adversely affect our business, financial condition or results of operations. In addition, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition or results of operations.

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We rely on a few key employees whose absence or loss could adversely affect our business.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services could adversely affect our business. In particular, the loss of the services of one or more members of our executive team, including our Chief Executive Officer, Travis D. Stice, could disrupt our operations. We have employment agreements with these executives which contain restrictions on competition with us in the event they cease to be employed by us. However, as a practical matter, such employment agreements may not assure the retention of our employees. Further, we do not maintain "key person" life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

A significant reduction by Wexford of its ownership interest in us could adversely affect us

Prior to October 11, 2012, Wexford beneficially owned 100% of our equity interests. Upon completion of our initial public offering, Wexford beneficially owned approximately 44.4% of our common stock. Upon completion of this offering, assuming Wexford or its affiliates make no additional purchases of our common stock, Wexford will beneficially own approximately 25.5% of our common stock (approximately 25.2% if the underwriters' option to purchase additional shares is exercised in full). Further, the Chairman of our Board of Directors is an affiliate of Wexford. We believe that Wexford's substantial ownership interest in us provides Wexford with an economic incentive to assist us to be successful. Upon the expiration of the lock-up restrictions on transfers or sales of our securities by or on behalf of entities controlled by Wexford imposed in connection with this offering, Wexford will not be subject to any obligation to maintain its ownership interest in us and may elect at any time thereafter to sell all or a substantial portion of or otherwise reduce its ownership interest in us. If Wexford sells all or a substantial portion of its ownership interest in us, Wexford may have less incentive to assist in our success and its affiliate(s) that serve as members of our board of directors may resign. Such actions could adversely affect our ability to successfully implement our business strategies which could adversely affect our cash flows or results of operations. We also receive certain services, including drilling services from entities controlled by Wexford. These service contracts may generally be terminated on 30-days notice. In the event Wexford ceases to own a significant ownership interest in us, such services may not be available to us on terms acceptable to us, if at all.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment and adversely affect our business, financial condition or results of operations.

Our drilling activities are subject to many risks. For example, we cannot assure you that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond our control, and increases in those costs can adversely affect the economics of a project. Further, our drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

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

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Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

Historically, we have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and expected future market prices for oil and natural gas, expected costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, gas leaks and ruptures or discharges of toxic gases. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations and repairs required to resume operations.

We endeavor to contractually allocate potential liabilities and risks between us and the parties that provide us with services and goods, which include pressure pumping and hydraulic fracturing, drilling and cementing services and tubular goods for surface, intermediate and production casing. Under our agreements with our vendors, to the extent responsibility for environmental liability is allocated between the parties, (i) our vendors generally assume all responsibility for control and removal of pollution or contamination which originates above the surface of the land and is directly associated with such vendors’ equipment while in their control and (ii) we generally assume the responsibility for control and removal of all other pollution or contamination which may occur during our operations, including pre-existing pollution and pollution which may result from fire, blowout, cratering, seepage or any other uncontrolled flow of oil, gas or other substances, as well as the use or disposition of all drilling fluids. In addition, we generally agree to indemnify our vendors for loss or destruction of vendor-owned property that occurs in the well hole (except for damage that occurs when a vendor is performing work on a footage, rather than day work, basis) or as a result of the use of equipment, certain corrosive fluids, additives, chemicals or proppants. However, despite this general allocation of risk, we might not succeed in enforcing such contractual allocation, might incur an unforeseen liability falling outside the scope of such allocation or may be required to enter into contractual arrangements with terms that vary from the above allocations of risk. As a result, we may incur substantial losses which could materially and adversely affect our financial condition and results of operation.

In accordance with what we believe to be customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flow. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Since hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean-up costs stemming from a sudden and accidental pollution event. However, we may

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not have coverage if we are unaware of the pollution event and unable to report the "occurrence" to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to succeed.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

We will be subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we are unable to timely comply with Section 404 or if the costs related to compliance are significant, our profitability, stock price and results of operations and financial condition could be materially adversely affected.

We will be required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002 as of December 31, 2013. Section 404 requires that we document and test our internal control over financial reporting and issue management's assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm opine on those internal controls if and when we become a large accelerated filer, as defined in the SEC rules, or if we otherwise cease to qualify for an exemption from the requirement to provide auditors' attestation on internal controls afforded to emerging growth companies under the "Jumpstart Our Business Startups Act" enacted by the U.S. Congress in April 2012. We are currently evaluating our existing controls against the standards adopted by the Committee of Sponsoring Organizations of the Treadway Commission. During the course of our ongoing evaluation and integration of our internal control over financial reporting, we may identify areas requiring improvement, and we may have to design enhanced processes and controls to address issues identified through this review.

We believe that the out-of-pocket costs, the diversion of management's attention from running the day-to-day operations and operational changes caused by the need to comply with the requirements of Section 404 of the Sarbanes-Oxley Act could be significant. If the time and costs associated with such compliance exceed our current expectations, our results of operations could be adversely affected.

We cannot be certain at this time that we will be able to successfully complete the procedures, certification and attestation requirements of Section 404 of the Sarbanes-Oxley Act or that we or our auditors will not identify material weaknesses in internal control over financial reporting. If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act or if we or our auditors identify and report such material weaknesses, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

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Increased costs of capital could adversely affect our business.

Our business and operating results could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We recorded stock-based compensation expense in 2012 and the first quarter of 2013 and we may incur substantial additional compensation expense related to our future grants of stock compensation which may have a material negative impact on our operating results for the foreseeable future.

As a result of outstanding stock-based compensation awards, we recorded $6.3 million of compensation expense in 2012 and $1.4 million of compensation expense in the first six months of 2013. In addition, our compensation expenses may increase in the future as compared to our historical expenses because of the costs associated with our existing and possible future incentive plans. These additional expenses could adversely affect our net income. The future expense will be dependent upon the number of share-based awards issued and the fair value of the options or shares of common stock at the date of the grant; however, they may be significant. We will recognize expenses for restricted stock awards and stock options generally over the vesting period of awards made to recipients.

Our level of indebtedness may increase and reduce our financial flexibility.

As of the date of this prospectus, we have $180.0 million of borrowing base availability under our revolving credit facility. In the future, we may incur significant indebtedness under our revolving credit facility or otherwise in order to make acquisitions, to develop our properties or for other purposes.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt could increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

Our revolving credit facility contains restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities.

Our revolving credit facility contains restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;

- create additional liens;

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- sell assets;
- merge or consolidate with another entity;
- pay dividends or make other distributions;
- engage in transactions with affiliates; and
- enter into certain swap agreements.

In addition, our revolving credit facility requires us to maintain certain financial ratios and tests. The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

If we are unable to comply with the restrictions and covenants in our revolving credit facility, there could be an event of default under the terms of our revolving credit facility, which could result in an acceleration of repayment.

If we are unable to comply with the restrictions and covenants in our revolving credit facility, there could be an event of default under the terms of this facility. Our ability to comply with these restrictions and covenants, including meeting the financial ratios and tests under our revolving credit facility, may be affected by events beyond our control. As a result, we cannot assure that we will be able to comply with these restrictions and covenants or meet such financial ratios and tests. In the event of a default under our revolving credit facility, the lenders under such facility could terminate their commitments to lend or accelerate the loans and declare all amounts borrowed due and payable. If any of these events occur, our assets might not be sufficient to repay in full all of our outstanding indebtedness and we may be unable to find alternative financing. Even if we could obtain alternative financing, it might not be on terms that are favorable or acceptable to us. Additionally, we may not be able to amend our revolving credit facility or obtain needed waivers on satisfactory terms.

Our borrowings under our revolving credit facility expose us to interest rate risk.

Our earnings are exposed to interest rate risk associated with borrowings under our revolving credit facility, which bear interest at a rate elected by us that is based on the prime, LIBOR or federal funds rate plus margins ranging from 1.25% to 3.50% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. As of May 21, 2013 (the last day on which borrowings were outstanding under our revolving credit facility), the weighted average interest rate on such borrowings was 2.70%. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

Any significant reduction in our borrowing base under our revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Under our revolving credit facility, which currently provides for a $180.0 million borrowing base, we are subject to semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Related to this Offering and Our Common Stock

Our two largest stockholders control a significant percentage of our common stock, and their interests may conflict with those of our other stockholders.

Upon completion of this offering, Wexford and Gulfport (assuming neither Wexford nor Gulfport or any of their respective affiliates makes any additional purchases of our common stock) will beneficially own approximately 25.5% and 12.3%, respectively, of our common stock or 25.2% and 12.1%, respectively, if the underwriters exercise their option to purchase additional shares in full. See "Principal Stockholders" on page 77 of this prospectus. In addition, individuals affiliated with Wexford and Gulfport serve on our Board of Directors, and Gulfport has the right to designate one individual as a nominee for election to our Board of Directors so long as it continues to beneficially own more than 10% of our outstanding common stock. As a result, Wexford and Gulfport, together, are able to control, and Wexford alone will continue to be able to exercise significant influence over, matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of Wexford and Gulfport with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders. This continued concentrated ownership will make it impossible for another company to acquire us and for you to receive any related takeover premium for your shares unless Wexford approves the acquisition.

The corporate opportunity provisions in our certificate of incorporation could enable Wexford, our equity sponsor, or other affiliates of ours to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our certificate of incorporation, among other things:

- permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested;
- permits any of our stockholders, officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provides that if any director or officer of one of our affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to such affiliates and that director or officer will not be deemed to have (i) acted in a manner inconsistent with his or her fiduciary or other duties to us regarding the opportunity or (ii) acted in bad faith or in a manner inconsistent with our best interests.

These provisions create the possibility that a corporate opportunity that would otherwise be available to us may be used for the benefit of one of our affiliates.

We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders' best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies. As described under the caption "Related Party Transactions" beginning on page 73 of this prospectus, these transactions include, among others, drilling services provided to us by Bison Drilling and Field Services, LLC, real property leased by us from Fasken Midland, LLC and certain administrative services provided to us by Everest Operations Management LLC. Each of these entities is either controlled by or affiliated with Wexford, and the resolution of any conflicts that may arise in connection with such related party transactions, including pricing, duration or other terms of service, may not always be in our or our stockholders' best interests because Wexford may have the ability to influence the outcome of these conflicts. For a discussion of potential conflicts, see "—Risks Related to this Offering and our

Common Stock—Our two largest stockholders control a significant percentage of our common stock, and their interests may conflict with those of our other stockholders” on page 33 of this prospectus.
We incur increased costs as a result of being a public company, which may significantly affect our financial condition.
We completed our initial public offering in October 2012. As a public company, we incur significant legal, accounting and other expenses that we did not incur as a private company. We also incur costs associated with our public company

reporting requirements and with corporate governance requirements, including requirements under the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the Financial Industry Regulatory Authority. These rules and regulations increase our legal and financial compliance costs and make some activities more time-consuming and costly, and we expect that these costs may increase further after we are no longer an "emerging growth company." These rules and regulations make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers.

However, for as long as we remain an "emerging growth company" as defined in the Jumpstart Our Business Startups Act of 2012, we intend to take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not "emerging growth companies" including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved.

Since the market value of our common stock held by non-affiliates exceeded $700 million as of June 30, 2013, we will cease to be an "emerging growth company" as of December 31, 2013. After we are no longer an "emerging growth company," we expect to incur significant additional expenses and devote substantial management effort toward ensuring compliance with those requirements applicable to companies that are not "emerging growth companies," including Section 404 of the Sarbanes-Oxley Act. See "—Risks Related to the Oil and Natural Gas Industry and Our Business—We will be subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we are unable to timely comply with Section 404 or if the costs related to compliance are significant, our profitability, stock price and results of operations and financial condition could be materially adversely affected" on page 30 of this prospectus.

We are an "emerging growth company" and we cannot be certain if the reduced disclosure requirements applicable to emerging growth companies will make our common stock less attractive to investors.

We are, and through December 31, 2013 will remain, an "emerging growth company," as defined in the Jumpstart our Business Startups Act of 2012, and until we cease to be an emerging growth company we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies, including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved. Investors may find our common stock less attractive because we rely on these exemptions. If some investors find our common stock less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

Under the Jumpstart Our Business Startups Act, "emerging growth companies" can delay adopting new or revised accounting standards until such time as those standards apply to private companies. We have irrevocably elected not to avail ourselves to this exemption from new or revised accounting standards and, therefore, we will be subject to the same new or revised accounting standards as other public companies that are not "emerging growth companies."

If the price of our common stock fluctuates significantly, your investment could lose value.

Although our common stock is listed on the NASDAQ Select Global Market, we cannot assure you that an active public market will continue for our common stock. If an active public market for our common stock does not continue, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or "float" for our stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us. Furthermore, the stock market is subject to significant price and volume fluctuations, and the price of our common stock could fluctuate widely in response to several factors, including:

- our quarterly or annual operating results;
- changes in our earnings estimates;
- investment recommendations by securities analysts following our business or our industry;
- additions or departures of key personnel;
- changes in the business, earnings estimates or market perceptions of our competitors;

- our failure to achieve operating results consistent with securities analysts' projections;
- changes in industry, general market or economic conditions; and
- announcements of legislative or regulatory changes.

The stock market has experienced extreme price and volume fluctuations in recent years that have significantly affected the quoted prices of the securities of many companies, including companies in our industry. The changes often appear to occur without regard to specific operating performance. The price of our common stock could fluctuate based upon factors that have little or nothing to do with our company and these fluctuations could materially reduce our stock price.

Future sales of our common stock, or the perception that such future sales may occur, may cause our stock price to decline.

Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. See "Shares Eligible for Future Sale" beginning on page 83 of this prospectus. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock. Except for any shares purchased by our affiliates, all of the shares sold in our initial public offering, our May 2013 offering and the June 2013 secondary offering are, and all of the shares sold in this offering will be, freely tradable. Our directors and executive officers, Gulfport and certain entities controlled by Wexford are subject to agreements that limit their ability to sell our common stock held by them. These holders cannot sell or otherwise dispose of any shares of our common stock for a period of 60 days after the date of this prospectus, or in the case of Gulfport, 60 days after the date of the prospectus (June 18, 2013) for the June 2013 secondary offering, without the prior written approval of Credit Suisse Securities (USA) LLC. However, these lock-up agreements are subject to certain specific exceptions, including transfers of common stock as a bona fide gift or by will or intestate succession and transfers to such person's immediate family or to a trust or to an entity controlled by such holder, provided that the recipient of the shares agrees to be bound by the same restrictions on sales and, in the case of our executive officers and directors, the right of such individuals to sell up to 300,000 shares in the aggregate. In connection with this offering, Credit Suisse Securities (USA) LLC granted a release of the lock-up agreements entered into by us, each of our directors and officers and certain entities controlled by Wexford in connection with the June 2013 secondary offering. In connection with our initial public offering, we also granted DB Energy Holdings LLC, or DB Holdings, and Gulfport certain registration rights obligating us to register with the SEC their shares of our common stock. In the event that one or more of our stockholders sells a substantial amount of our common stock in the public market, or the market perceives that such sales may occur, the price of our stock could decline.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrade our stock or if our operating results do not meet their expectations, our stock price could decline.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of the company, which could adversely affect the price of our common stock.

The existence of some provisions in our certificate of incorporation and bylaws and Delaware corporate law could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders. Our certificate of incorporation and bylaws contain provisions that may make acquiring control of our company difficult, including:

- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders;

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- limitations on the ability of our stockholders to call a special meeting and act by written consent;
- the ability of our board of directors to adopt, amend or repeal bylaws, and the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained for stockholders to amend our bylaws;
- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to remove directors;
- the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to amend our certificate of incorporation; and
- the authorization given to our board of directors to issue and set the terms of preferred stock without the approval of our stockholders.

These provisions also could discourage proxy contests and make it more difficult for you and other stockholders to elect directors and take other corporate actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

We do not intend to pay cash dividends on our common stock in the foreseeable future, and therefore only appreciation of the price of our common stock will provide a return to our stockholders.

We currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future. Any future determination as to the declaration and payment of cash dividends will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors deemed relevant by our board of directors. In addition, the terms of our revolving credit facility prohibit us from paying dividends and making other distributions. As a result, only appreciation of the price of our common stock, which may not occur, will provide a return to our stockholders.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus, including the documents incorporated by reference, contains forward-looking statements. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about our:

- business strategy;
- exploration and development drilling prospects, inventories, projects and programs;
- expectations regarding the consummation of the pending acquisitions described under "Summary—Recent Developments—Pending Acquisitions";
- 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 of these types of statements, other than statements of historical fact included or incorporated by reference in this prospectus, are forward-looking statements. These forward-looking statements may be found in the “Prospectus Summary,” “Risk Factors” and “Business” beginning on pages 1, 15 and 50, respectively, in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our Annual Report for the year ended December 31, 2012 incorporated by reference herein and in our Quarterly Reports on Form 10-Q for the three months ended March 31, 2013 and June 30, 2013 incorporated by reference herein and elsewhere in this prospectus and the documents incorporated herein. In some cases, you can identify forward-looking statements by terminology such as “may,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “s “continue,” the negative of such terms or other comparable terminology.

The forward-looking statements contained or incorporated by reference in this prospectus are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, our management’s assumptions about future events may prove to be inaccurate. Our management cautions all readers that the forward-looking statements contained in this prospectus are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the many factors including those described under “Risk Factors” herein and in our Annual Report on Form 10-K for the year ended December 31, 2012 incorporated by reference herein and elsewhere in this prospectus. All forward-looking statements contained in this prospectus or included in a document incorporated by reference herein speak only as of the date hereof or thereof, respectively. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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USE OF PROCEEDS

Our net proceeds from the sale of 4,000,000 shares of common stock in this offering are estimated to be approximately $154.3 million, after deducting underwriting discounts and commissions and estimated offering expenses. The net proceeds would be approximately $177.4 million if the underwriters' option to purchase additional shares is exercised in full. Following the closing of this offering, we intend to use the net proceeds to fund our pending acquisitions of additional acreage in the Permian Basin. To the extent the pending acquisitions are not consummated, or the applicable purchase prices are less than we currently estimate, we intend to use any remaining net proceeds from this offering to fund a portion of our exploration and development activities and for general corporate purposes, which may include leasehold interest and property acquisitions and working capital.

DIVIDEND POLICY

We have never declared or paid any cash dividends on our capital stock. We currently intend to retain all available funds and any future earnings for use in the operation and expansion of our business and do not anticipate declaring or paying any cash dividends in the foreseeable future. Any future determination as to the declaration and payment of dividends will be at the discretion of our board of directors and will depend on then-existing conditions, including our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors that our board of directors considers relevant. In addition, the terms of our revolving credit facility restrict the payment of dividends to the holders of our common stock and any other equity holders.

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CAPITALIZATION

The following table sets forth our cash and cash equivalents and capitalization as of June 30, 2013:

- on an actual basis; and
- as adjusted to give effect to the sale of 4,000,000 shares of our common stock in this offering, our receipt of an estimated $154.3 million of net proceeds from this offering, after deducting underwriting discounts and commissions and estimated offering expenses, and the use of the net proceeds to fund the pending acquisitions as described under the caption “Use of Proceeds” on page 38.

You should read the following table in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our combined consolidated financial statements and related notes which are incorporated by reference into this prospectus.

	As of June 30, 2013	
	Actual	As Adjusted
Cash and cash equivalents	$81,898,000	$71,158,000
Debt:		
Revolving credit facility	$—	$—
Note payable	266,000	266,000
Total debt	266,000	266,000
Stockholders’ equity:		
Common stock, par value $0.01; 100,000,000 shares authorized and 42,161,532 shares issued and outstanding actual; and 100,000,000 shares authorized and 46,161,532 shares issued and outstanding as adjusted	422,000	462,000
Additional paid-in capital	659,394,000	813,614,000
Accumulated deficit	(32,207,000)	(32,207,000)
Total stockholders’ equity	627,609,000	781,869,000
Total capitalization	$627,875,000	$782,135,000

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PRICE RANGE OF COMMON STOCK

Our common stock is listed and traded on the NASDAQ Global Select Market under the symbol "FANG." Our common stock began trading on October 12, 2012 at an initial public offering price of $17.50 per share.

The following table sets forth the range of high and low sales prices of our common stock for the periods presented:

Year	Quarter	High	Low
2012	4th Quarter(1)	$19.89	$15.65
2013	1st Quarter	$27.21	$18.60
2013	2nd Quarter	$35.91	$23.83
2013	3rd Quarter(2)	$43.84	$33.42

(1) Represents the period from October 12, 2012, the date on which our common stock began trading on the NASDAQ Global Select Market, through December 31, 2012.

(2) Through August 14, 2013.

The closing price of our common stock on the NASDAQ Global Select Market on August 14, 2013 was $40.45 per share. Immediately prior to this offering, we had 42,161,532 issued and outstanding shares of common stock, which were held by six holders of record. This number does not include owners for whom common stock may be held in "street" name or whose common stock is restricted.

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SELECTED HISTORICAL COMBINED CONSOLIDATED FINANCIAL DATA

The following selected historical combined consolidated financial data as of December 31, 2012 and 2011 and for each of the three years in the period ended December 31, 2012 are derived from our audited combined consolidated financial statements incorporated by reference into this prospectus. The selected combined consolidated balance sheet data as of December 31, 2010 and the selected historical combined consolidated financial data for 2009 and 2008 are derived from our audited financial statements of the Predecessors not included in or incorporated by reference into this prospectus. The consolidated statements of operations data for the six months ended June 30, 2013 and June 30, 2012 and the consolidated balance sheet data at June 30, 2013 are derived from our unaudited consolidated financial statements appearing in our most recent Quarterly Report on Form 10-Q incorporated by reference into this prospectus. The consolidated balance sheet data at June 30, 2012 are derived from our unaudited consolidated financial statements that are not included in or incorporated by reference into this prospectus. The unaudited pro forma C Corporation financial data presented give effect to income taxes assuming we operated as a taxable corporation since inception for the 2011, 2010, 2009 and 2008 columns and since December 31, 2011 for the 2012 columns. Operating results for the periods presented below are not necessarily indicative of results that may be expected for any future periods. You should review this information together with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our historical combined consolidated financial statements and related notes which are incorporated by reference into this prospectus.

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	Six Months Ended June 30,		Year Ended December 31,				
	2013	2012(1)	2012(2)	2011(1)	2010(1)	2009	2008
Statement of Operations Data:							
Oil and natural gas revenues	$74,303,000	$32,381,000	$74,962,000	$47,875,000	$26,442,000	$12,716,000	$18,239,000
Other revenues	—	—	—	1,491,000	811,000	—	—
Expenses:							
Lease operating expense	11,522,000	6,318,000	16,793,000	10,597,000	4,589,000	2,366,000	3,375,000
Production taxes	3,623,000	1,579,000	3,691,000	2,366,000	1,347,000	663,000	1,009,000
Gathering and transportation	380,000	146,000	424,000	202,000	106,000	42,000	53,000
Oil and natural gas services	—	—	—	1,733,000	811,000	—	—
Depreciation, depletion and amortization	25,553,000	10,416,000	26,273,000	15,601,000	8,145,000	3,216,000	10,200,000
Impairment of oil and gas properties	—	—	—	—	—	—	83,164,000
General and administrative	5,092,000	2,837,000	10,376,000	3,655,000	3,036,000	5,063,000	5,460,000
Asset retirement obligation accretion expense	88,000	41,000	98,000	65,000	38,000	28,000	24,000
Total expenses	46,258,000	21,337,000	57,655,000	34,219,000	18,072,000	11,378,000	103,285,000
Income (loss) from operations	28,045,000	11,044,000	17,307,000	15,147,000	9,181,000	1,338,000	(85,046,000)
Other income (expense):							
Interest income	—	2,000	3,000	11,000	34,000	35,000	625,000
Interest expense	(1,020,000)	(2,054,000)	(3,610,000)	(2,528,000)	(836,000)	(11,000)	—
Other income	777,000	1,011,000	2,132,000	—	—	—	—
Gain (loss) on derivative instruments	3,029,000	5,165,000	2,617,000	(13,009,000)	(148,000)	(4,068,000)	(9,528,000)
Loss from equity investment	—	(67,000)	(67,000)	(7,000)	—	—	—
	2,786,000	4,057,000	1,075,000	(15,533,000)	(950,000)	(4,044,000)	(8,903,000)

Total other income (expense), net							
Net income (loss) before income taxes	30,831,000	15,101,000	18,382,000	(386,000)	8,231,000	(2,706,000)	(93,949,000)
Provision for income taxes	10,964,000	—	54,903,000	—	—	—	—
Net income (loss)	$19,867,000	$15,101,000	$(36,521,000)	$(386,000)	$8,231,000	$(2,706,000)	$(93,949,000)
Earnings per common share							
Basic	$0.52						
Diluted	$0.52						
Weighted average common shares outstanding							
Basic	38,237,149						
Diluted	38,476,719						
Pro Forma C Corporation Data(3):							
Net income (loss) before income taxes		$15,101,000	$18,382,000	$(386,000)	$8,231,000	$(2,706,000)	$(93,949,000)
Pro forma for income taxes		5,384,000	6,553,000	—	—	—	—
Pro forma net income (loss)		$9,717,000	$11,829,000	$(386,000)	$8,231,000	$(2,706,000)	$(93,949,000)
Pro forma earnings per common share(4)							
Basic		$0.66	$0.60				
Diluted		$0.66	$0.60				
Weighted average shares outstanding(4)							
Basic		14,697,496	19,720,734				
Diluted		14,697,496	19,723,774				

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	Six Months Ended June 30,		Year Ended December 31,				
	2013	2012[(1)]	2012[(2)]	2011[(1)]	2010[(1)]	2009	2008
Selected Cash Flow and Other Financial Data:							
Net income (loss)	$19,867,000	$15,101,000	$(36,521,000)	$(386,000)	$8,231,000	$(2,706,000)	$(93,
Depreciation, depletion and amortization	25,553,000	10,416,000	26,273,000	16,104,000	8,145,000	3,216,000	10,20
Other non-cash items	6,847,000	(4,273,000)	56,390,000	13,845,000	344,000	4,109,000	92,71
Change in operating assets and liabilities	(2,469,000)	1,417,000	3,550,000	1,435,000	(11,528,000)	(1,917,000)	3,076
Net cash provided by operating activities	$49,798,000	$22,661,000	$49,692,000	$30,998,000	$5,192,000	$2,702,000	$12,0
Net cash used in investing activities	$(138,675,000)	$(59,616,000)	$(183,078,000)	$(81,108,000)	$(55,236,000)	$(32,150,000)	$(84,
Net cash provided by financing activities	$144,417,000	$32,337,000	$152,785,000	$52,950,000	$51,733,000	$23,849,000	$80,1

	Six Months Ended June 30,		Year Ended December 31,				
	2013	2012[(1)]	2012[(2)]	2011[(1)]	2010[(1)]	2009	2008
Balance sheet data:							
Cash and cash equivalents	$81,898,000	$2,341,000	$26,358,000	$6,959,000	$4,119,000	$2,430,000	$8,02
Other current assets	34,638,000	23,226,000	23,917,000	23,853,000	20,947,000	2,263,000	1,390
Oil and gas properties, net — using full cost method of accounting	677,446,000	268,353,000	552,640,000	220,465,000	144,552,000	89,778,000	73,78
Well equipment to be used in development of oil and gas properties	—	—	—	—	—	5,413,000	8,503
Other property and equipment, net	3,726,000	1,540,000	1,602,000	684,000	11,059,000	106,000	161,0
Other assets	931,000	1,998,000	2,184,000	11,617,000	638,000	83,000	—
Total assets	$798,639,000	$297,458,000	$606,701,000	$263,578,000	$181,315,000	$100,073,000	$91,8
Current liabilities	$97,487,000	$51,897,000	$79,232,000	$42,298,000	$19,070,000	$13,973,000	$18,0
Note payable-long term	121,000	339,000	193,000	—	—	—	—
Note payable credit facility-long term	—	90,000,000	—	85,000,000	44,767,000	—	—
Note payable-related party-long term	—	14,110,000	—	—	—	—	—
Derivative instruments-long term	—	1,667,000	388,000	6,139,000	1,374,000	1,416,000	2,868
Asset retirement obligations	2,324,000	1,221,000	2,125,000	1,104,000	742,000	482,000	374,0

Deferred income taxes	71,098,000	—	62,695,000	—	—	—	—
Stockholders' equity	627,609,000	138,224,000	462,068,000	129,037,000	115,362,000	84,202,000	70,61
Total liabilities and member's/stockholders equity	$798,639,000	$297,458,000	$606,701,000	$263,578,000	$181,315,000	$100,073,000	$91,8

	Six Months Ended June 30,		Year Ended December 31,				
	2013	2012(1)	2012(2)	2011(1)	2010(1)	2009	2008
Other financial data:							
Adjusted EBITDA(5)	$55,399,000	$22,806,000	$48,223,000	$31,758,000	$17,398,000	$4,617,000	$8,967,000

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(1) The years ended December 31, 2011 and 2010 and the six months ended June 30, 2012 reflect the combined historical financial data of Windsor Permian LLC and Windsor UT LLC due to the transfer of a business between entities under common control. See Note 1 to our combined consolidated financial statements incorporated by reference into this prospectus.

(2) The year ended December 31, 2012 reflects (a) the combined historical financial data of Windsor Permian LLC and Windsor UT LLC due to the transfer of a business between entities under common control and (b) the results of operations attributable to the acquisition of properties from Gulfport Energy Corporation beginning October 11, 2012, the closing date of the property acquisition. See Note 1 and Note 2 to our combined consolidated financial statements incorporated by reference into this prospectus.

(3) Diamondback was formed as a holding company 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. Diamondback is a C-Corp under the Internal Revenue Code and is subject to income taxes. The Company computed a pro forma income tax provision for 2012 as if the Company and the Predecessors were subject to income taxes since December 31, 2011. For 2011, 2010, 2009 and 2008 comparative purposes, we have included pro forma financial data to give effect to income taxes assuming the earnings of the Company and the Predecessors had been subject to federal income tax as a subchapter C corporation since inception. If the earnings of the Company and the Predecessors had been subject to federal income tax as a subchapter C corporation since inception, we would have incurred net operating losses for income tax purposes in each period. We would have been in a net deferred tax asset, or DTA, position as a result of such tax losses and would have recorded a valuation allowance to reduce each period's DTA balance to zero. A valuation allowance to reduce each period's DTA would have resulted in an equal and offsetting credit for the respective expenses or an equal and offsetting debit for the respective benefits for income taxes, with the resulting tax expenses for each 2011 and 2010 of zero. The unaudited pro forma data is presented for informational purposes only, and does not purport to project our results of operations for any future period or our financial position as of any future date. The pro forma tax provision has been calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, incorporating permanent differences. See Note 1 to our combined consolidated financial statements incorporated by reference into this prospectus.

(4) The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued upon the merger of Diamondback Energy LLC into Diamondback were outstanding for the entire year. Diluted earnings per share reflects the potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock awards and units were fully vested. During periods in which the Company realizes a net loss, options and restricted stock awards would not be dilutive to net loss per share and conversion into common stock is assumed not to occur. See Note 1 to our combined consolidated financial statements incorporated by reference into this prospectus.

(5) Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDA as net income (loss) before income taxes, gain/loss on derivative instruments, interest expense, depreciation, depletion and amortization, impairment of oil and gas properties, non-cash equity based compensation and asset retirement obligation accretion expense. Adjusted EBITDA is not a measure of net income (loss) as determined by United States' generally accepted accounting principles, or GAAP. Management believes Adjusted EBITDA is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance,

such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measure of other companies or to such measure in our revolving credit facility.

The following presents a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measure of net income (loss).

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	Six Months Ended June 30,		Year Ended December 31,				
	2013	2012(1)	2012(2)	2011(1)	2010(1)	2009	2008
Net income (loss):	$19,867,000	$15,101,000	$(36,521,000)	$(386,000)	$8,231,000	$(2,706,000)	$(93,949,000)
(Gain) loss on derivative instruments	(3,029,000)	(5,165,000)	(2,617,000)	13,009,000	148,000	4,068,000	9,528,000
Interest expense	1,020,000	2,054,000	3,610,000	2,528,000	836,000	11,000	—
Depreciation, depletion and amortization	25,553,000	10,416,000	26,273,000	16,104,000	8,145,000	3,216,000	10,200,000
Impairment of oil and gas properties	—	—	—	—	—	—	83,164,000
Non-cash equity based compensation expense	936,000	359,000	2,477,000	438,000	—	—	—
Asset retirement obligation accretion expense	88,000	41,000	98,000	65,000	38,000	28,000	24,000
Deferred income tax provision	10,964,000	—	54,903,000	—	—	—	—
Adjusted EBITDA	$55,399,000	$22,806,000	$48,223,000	$31,758,000	$17,398,000	$4,617,000	$8,967,000

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UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENT

Diamondback Energy, Inc.

Unaudited Pro Forma Condensed Consolidated Financial Statement

Introduction

The following unaudited pro forma condensed consolidated statement of operations and related notes of the Company have been prepared to show the effect of the Gulfport transaction and the distribution by Windsor Permian to its equity holders of its minority equity interests in Bison and Muskie. The unaudited pro forma condensed consolidated statement of operations should be read together with the Company's Annual Report on Form 10-K for the year ended December 31, 2012, filed with the SEC on March 1, 2013 and the historical Statements of Revenues and Direct Operating Expenses of certain property interests of Gulfport Energy Corporation included in this prospectus. The accompanying unaudited pro forma condensed consolidated statement of operations is based on assumptions and include adjustments as explained in the accompanying notes.

The acquisition of certain property interests of Gulfport Energy Corporation (the Gulfport properties) was treated as a business combination accounted for under the acquisition method of accounting with the identifiable assets recognized at fair value on the date of transfer.

The pro forma data presented reflect events directly attributable to the described transactions and certain assumptions the Company believes are reasonable. The pro forma data are not necessarily indicative of financial results that would have been attained had the described transactions occurred on the dates indicated below. The pro forma data also necessarily exclude various operation expenses related to the Gulfport properties and the statement of operations should not be viewed as indicative of operations in future periods. As the current operator of the properties acquired by the Company upon completion of the Gulfport transaction, the Company does not expect any material impact from these transactions on its existing employees or infrastructure.

The Gulfport transaction was completed on October 11, 2012, and the distribution of the equity interests in Bison and Muskie occurred in June 2012.

The unaudited pro forma condensed consolidated statement of operations for the year ended December 31, 2012 assumes that the described transactions occurred on January 1, 2012.

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Diamondback Energy, Inc.
Unaudited Pro Forma Condensed Consolidated Statement of Operations
Year ended December 31, 2012

	Diamondback Energy, Inc. Historical	Gulfport Properties Nine Months Ended September 30, 2012 Historical	Pro Forma Adjustments		Pro Forma
Revenues:					
Oil and natural gas revenues	$74,962,000	$21,217,000	$1,276,000	(a)	$97,455,000
Costs and expenses:					
Lease operating expenses	16,793,000	6,359,000	209,000	(a)	23,361,000
Production taxes	3,691,000	1,119,000	(6,000)	(a)	4,804,000
Gathering and transportation	424,000	—	99,000	(a)	523,000
Depreciation, depletion and amortization	26,273,000	—	7,932,000	(c)	34,205,000
General and administrative	10,376,000	—	—		10,376,000
Asset retirement obligation accretion expense	98,000	—	24,000	(b)	122,000
Total costs and expenses	57,655,000	7,478,000	8,258,000		73,391,000
Income (loss) from operations	17,307,000	13,739,000	(6,982,000)		24,064,000
Other income (expense)					
Interest income	3,000	—	—		3,000
Interest expense	(3,610,000)	—	—		(3,610,000)
Other income	2,132,000	—	—		2,132,000
Gain on derivative instruments	2,617,000	—	—		2,617,000
Loss from equity investment	(67,000)	—	67,000	(d)	—
Total other income (expense), net	1,075,000	—	67,000		1,142,000
Income (loss) before income taxes	18,382,000	13,739,000	(6,915,000)		25,206,000
Provision for income taxes					
Deferred income tax provision	54,903,000	—	—		54,903,000
Net income (loss)	$(36,521,000)	$13,739,000	$(6,915,000)		$(29,697,000)
Pro forma loss per common share[e]					
Basic					$(1.15)
Diluted					$(1.15)
Pro forma weighted average common shares outstanding[e]					
Basic					25,856,823
Diluted					25,859,863

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Diamondback Energy, Inc.
Notes to Unaudited Pro Forma Condensed Consolidated
Financial Statements

1. Basis of Presentation

The historical financial information is derived from the historical financial statements of Diamondback Energy, Inc. and the historical statements of revenues and direct operating expenses of certain property interests of Gulfport Energy Corporation. The unaudited pro forma condensed consolidated statement of operations for the year ended December 31, 2012 assumes that the Gulfport transaction and the distribution of the equity interests in Bison and Muskie occurred on January 1, 2012.

2. Pro Forma Assumptions and Adjustments

We made the following adjustments in the preparation of the unaudited pro forma condensed consolidated statement of operations.

(a) To record the operating results of the certain property interests of Gulfport Energy Corporation from the nine months ended September 30, 2012 to the closing date of the Gulfport transaction on October 11, 2012.

(b) To record incremental accretion of discount of asset retirement obligations associated with the Gulfport transaction.

(c) To record incremental depletion, depreciation, and amortization of oil and natural gas properties associated with the Gulfport transaction, amortized on a unit-of-production basis over the remaining life of total proved reserves.

(d) To record the effects of the distribution of minority equity interests in Bison and Muskie to Windsor Permian's sole member which occurred on June 15, 2012.

(e) The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued in connection with the Gulfport transaction (7,914,036 shares) and to DB Holdings in connection with the merger of Diamondback Energy LLC with and into Diamondback Energy, Inc. (14,697,496 shares) were outstanding for the entire year. Diluted earnings per share reflects the potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock awards and units were fully vested.

3. Other Income Tax and Earnings Per Share Considerations

As presented in the unaudited pro forma condensed consolidated statement of operations, income tax expense includes the $54,142,000 charge relating to the change in tax status as of October 11, 2012 and the related income taxes incurred as a result of operations from October 11, 2012 to December 31, 2012. The following supplemental pro forma information gives effect to income taxes assuming the Company operated as a taxable corporation since December 31, 2011.

	Pro forma C Corporation Data[(a)]	Pro forma, as adjusted[(b)]
Income before income taxes	$18,382,000	$25,206,000
Pro forma provision for income taxes	6,553,000	8,973,000
Pro forma net income	$11,829,000	$16,233,000
Pro forma earnings per common share		
Basic	$0.60	$0.63
Diluted	$0.60	$0.63
Pro forma weighted average common shares outstanding		
Basic	19,720,734	25,856,823
Diluted	19,723,774	25,859,863

(a) The pro forma financial data adjusts the Diamondback Energy, Inc. historical column to give effect to income taxes assuming the earnings of the Company had been subject to federal income tax as a subchapter C corporation since December 31, 2011, thus excluding the $54,142,000 charge relating to the change in tax status as of October 11, 2012. The pro forma tax provision has been calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, incorporating permanent differences.

(b) The pro forma financial data adjusts the pro forma column to give effect to income taxes assuming the earnings of the Company had been subject to federal income tax as a subchapter C corporation since December 31, 2011, thus excluding the $54,142,000 charge relating to the change in tax status as of October 11, 2012. The pro forma tax provision has been

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calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, incorporating permanent differences.

4. Pro Forma Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDA as net income (loss) before income taxes, gain/loss on derivative instruments, interest expense, depreciation, depletion and amortization, impairment of oil and gas properties, non-cash equity based compensation and asset retirement obligation accretion expense. Adjusted EBITDA is not a measure of net income (loss) as determined by United States' generally accepted accounting principles, or GAAP. Management believes Adjusted EBITDA is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measure of other companies or to such measure in our credit facility.

The following presents a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the net loss reported in the unaudited pro forma condensed consolidated statement of operations.

	Year Ended December 31, 2012
Pro forma net loss:	$(29,697,000)
(Gain) loss on derivative instruments	(2,617,000)
Interest expense	3,610,000
Depreciation, depletion and amortization	34,205,000
Non-cash equity based compensation expense	2,477,000
Asset retirement obligation accretion expense	122,000
Deferred income tax provision	54,903,000
Pro forma Adjusted EBITDA	$63,003,000

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BUSINESS

General

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 49,861 additional net acres, which brought our total net acreage position in the Permian Basin to 54,035 net acres at June 30, 2013. We are the operator of approximately 99% of this acreage. As of June 30, 2013, we had drilled 230 gross (209 net) wells, and participated in an additional 19 gross (eight net) non-operated wells, in the Permian Basin. Of these 249 gross (216 net) wells, 240 were completed as producing wells and nine were in various stages of completion. In the aggregate, as of June 30, 2013, we held interests in 274 gross (242 net) producing wells in the Permian Basin. As discussed in more detail under "—Recent Developments—Pending Acquisitions," we have entered into agreements to acquire approximately 11,150 additional net acres in the Permian Basin.

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 ranks as the second largest oilfield in the United States, based on 2009 reserves.

As of December 31, 2012, our estimated proved oil and natural gas reserves were 40,210 MBOE based on a reserve report prepared by Ryder Scott Company, L.P., or Ryder Scott, our independent reserve engineers. Of these reserves, approximately 29.5% are classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate are from 306 vertical gross well locations on 40-acre spacing and four gross horizontal well locations. As of December 31, 2012, these proved reserves were approximately 65% oil, 21% natural gas liquids and 14% natural gas.

We have 867 identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data as of June 30, 2013, and we have an additional 1,128 identified potential vertical drilling locations based on 20-acre downspacing. We have also identified 862 potential horizontal drilling locations in multiple horizons on our acreage. We intend 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 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, range from 102 MBOE per well, consisting of 46 MBbls of oil, 151 MMcf of natural gas and 31 MBbls of natural gas liquids, to 158 MBOE per well, consisting of 112 MBbls of oil, 114 MMcf of natural gas and 27 MBbls of natural gas liquids, with an average EUR per well of 133 MBOE, consisting of 91 MBbls of oil, 101 MMcf of natural gas and 25 MBbls of natural gas liquids. 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.

Recent Developments

Pending Acquisitions. We recently entered into two separate definitive agreements to acquire additional leasehold interests in the Permian Basin for an aggregate purchase price of $165.0 million, subject to certain adjustments. On August 2, 2013, we entered into a purchase and sale agreement in which we agreed to acquire from an unrelated third party certain assets located in northwestern Martin County, Texas, consisting of a 100% working interest (80% net revenue interest) in 4,506 gross and net acres, with 16 gross and net producing vertical wells, an estimated 1,138

MBOE of proved developed reserves (including 167 MBOE attributable to two PDNP wells) as of July 1, 2013 and 457 gross (365 net) BOE per day of production during July 2013. We have identified approximately 96 gross and net horizontal drilling locations on this acreage, of which 32 gross and net locations are located in the Wolfcamp B interval, with lateral lengths expected to range from approximately 5,000 feet to 8,000 feet. In addition, on August 1, 2013, we entered into a purchase and sale agreement in which we agreed to acquire from an unrelated third party certain assets located in southwestern Dawson County, Texas, consisting of a 70% working

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interest (54% net revenue interest) in 9,390 gross (6,647 net) acres, with 28 gross (18 net) producing vertical wells, an estimated 838 MBOE of proved developed reserves (including 77 MBOE attributable to one PDNP well) as of June 1, 2013 and 777 gross (417 net) BOE per day of production during June 2013. We have identified approximately 156 gross (109 net) potential horizontal drilling locations on this acreage, of which 53 gross (37 net) locations are located in the Wolfcamp B interval, with lateral lengths ranging from approximately 5,000 feet to 9,500 feet. Estimated proved reserves for both acquisitions relate solely to existing vertical wells, are based on management's internal assessment of information provided to us in the course of our due diligence, and have not been verified by us or any independent petroleum engineers. Both acquisitions remain subject to completion of due diligence and satisfaction of other closing conditions and may not be completed. We will be the operator of all of the acreage to be acquired in these acquisitions. We expect to close these acquisitions by the end of September 2013. We intend to fund the purchase price for these acquisitions from cash on hand and the net proceeds from this offering. See "Use of Proceeds" included elsewhere in this prospectus.

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 with a 3,842 foot lateral in the Wolfcamp B interval. We are the operator of this well with a 100% working interest. It was completed in June 2012 and had a peak 24-hour IP rate of 618 BOE/d and a peak consecutive 30-day average initial production rate of 486 BOE/d, of which 86% was oil. Through June 30, 2013, the Janey 16H had produced a total of 61 MBbls of oil and 73 MMcf of natural gas. Our second horizontal well was the Kemmer 4209H in Midland County. It is a non-operated well in which we own a 47% working interest. It was completed in September 2012 in the Wolfcamp B interval with a 3,733 foot lateral. The production as reported to us by the operator was a peak 24-hour initial production rate of 892 BOE/d and a peak 30-day average initial production rate of 712 BOE/d, of which 85% was oil. Through June 30, 2013, the Kemmer 4209H had produced a total of 63 MBbls of oil and 64 MMcf of natural gas. Based on the decline curve analysis of the current production, we anticipate that the EUR for each of these wells will be in the range of 400 to 500 MBOE.

Subsequent to the Janey 16H and Kemmer 4209H wells, we have drilled or are currently drilling 17 horizontal wells as operator and have participated in one additional horizontal well as a non-operator, all of which are Wolfcamp B wells in various stages of development. The table below presents certain data regarding our horizontal wells.

Horizontal Wells: Midland County

Well Name	Lateral Length	Number of Frac Stages	Peak 24-HR IP (BOE/d)	Peak 30 Day IP Rate (BOE/d)	% Oil[(a)]
Kemmer 4209H[(b)]	3,733'	15	892	712[(d)]	85%
ST NW 2501H	4,451'	19	1,054	655[(d)]	90%
ST NW 2502H	4,351'	16	651	500[(c)]	88%
Sarah Ann 3812H[(b)]	4,830'	18	892	711[(d)]	88%
ST W 4301H	7,141'	29	1,136	916[(d)]	85%
ST W 701H	7,280'	29	1,042[(d)]	N/A[(e)]	94%
ST W 4302H	7,071'	30	701[(d)]	N/A[(e)]	93%
ST W 706H	7,541'	Currently completing 30 stage frac			

Horizontal Wells: Upton County

Well Name	Lateral Length	Number of Frac Stages	Peak 24-HR IP (BOE/d)	Peak 30 Day IP Rate (BOE/d)	% Oil[(a)]
Janey 16H	3,842'	16	618	486[(c)]	86%
Neal A Unit 8-1H	7,441'	32	871	697[(c)]	87%
Janey 3H	4,411'	19	724	488[(d)]	82%
Neal B Unit 8-2H	6,501'	26	1,134	617[(d)]	73%
Kendra A Unit 1H	7,411'	30	970	677[(d)]	82%

Jacee A Unit 1H	7,541’	30	1,085	632[d]	83%
Janey 2H	4,572’	19	930[d]	N/A[e]	87%
Janey 4H	4,564’	10	880[d]	N/A[e]	77%
Charlotte A Unit 1H	10,353’	Currently completing 39 stage frac			
Neal C Unit 8 3H	6,851’	Currently completing 15 stage frac			

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Horizontal Wells: Andrews County

Well Name	Lateral Length	Number of Frac Stages	Peak 24-HR IP (BOE/d)	Peak 30 Day IP Rate (BOE/d)	% Oil[(a)]
UL III 4-1H	4,051'	Flowback operations underway			
UL Viper 6-1H	7,540'	Well drilled; frac scheduled			

(a) During the period for which the Peak 30 day IP Rate is presented except in the case of the ST W 701H, Janey 2H and Janey 4H wells, which is based on the Peak 24-hour IP rate.
(b) Non-operated.
(c) On gas lift.
(d) On sub pump.
(e) A peak 30 day IP Rate is not available.

In addition, we are currently drilling three additional horizontal wells. The production results from the wells in Midland and Upton Counties, along with geoscience and engineering data that we have gathered and analyzed, give us confidence that our acreage in Midland and Upton Counties is prospective in the Wolfcamp B interval.

Our Business Strategy

Our business strategy is to increase stockholder value 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 June 30, 2013, we had 867 identified potential vertical drilling locations and 862 identified potential horizontal 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 June 30, 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 or are currently drilling 17 horizontal wells as operator and have participated in one additional horizontal well as a non-operator, 19 of which are Wolfcamp B wells and one of which is a Clearfork well. These wells have had lateral lengths ranging from approximately 4,300 feet to 10,300 feet. In the future, we expect that our optimal average lateral lengths will be in the range of 7,500 feet to 8,000 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 first six months of 2013, we were able to drill our horizontal wells with approximately 7,500 foot lateral lengths to total depth in an average of 21 days and we recently drilled a 10,353 foot lateral well in 19 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 three horizontal drilling rigs as of June 30, 2013, and currently intend to add a fourth horizontal rig in the fourth quarter of 2013, and are currently contemplating adding one or two horizontal drilling rigs in 2014.
- Leverage our experience operating in the Permian Basin. Our executive team, which has an average of approximately 24 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. The time to reach total depth, or TD, for our vertical Wolfberry wells decreased from an average of 18 days during the

second quarter of 2011 to an average of 14 days during the period from April 2012 through August 2012 to an average of 11 days during the fourth quarter of 2012 to an average of eight days during the second quarter of 2013, with three of our recent vertical wells reaching TD in less than seven days. Our focus on efficient drilling and completion techniques, and the reduction in time to reach TD, 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 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 88% 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. As discussed in more detail under "—Recent Developments—Pending Acquisitions," we have entered into agreements to acquire approximately 11,150 additional net acres in the Permian Basin.
- 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 December 28, 2012, the borrowing base under our revolving credit facility was redetermined, resulting in an increase in our availability to $135.0 million, and it was redetermined again on May 6, 2013, resulting in an increase in availability to $180.0 million. We used a portion of the net proceeds of our May 2013 common stock offering to repay all borrowings outstanding under our revolving credit facility and, as of the date of this prospectus, we have $180.0 million of borrowing base availability.

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 six months ended June 30, 2013 was approximately 73% oil, 15% natural gas liquids and 12% natural gas. As of December 31, 2012, our estimated net proved reserves were comprised of approximately 65% oil and 21% 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 June 30, 2013, we had 867 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 862 potential horizontal locations on our acreage. These locations exist across most of our acreage blocks and in multiple horizons. Of the 862 locations, 376 are in the Wolfcamp A horizon or the Wolfcamp B horizon, with the remaining locations in either the Clearfork, Spraberry, Wolfcamp C or Cline horizons.

We have assigned horizontal locations to the Lower Spraberry, but have not assigned locations to other intervals within the Spraberry, which we believe may have development potential. Our current horizontal location count is based on 880 foot spacing between wells in the Wolfcamp B horizon in Midland and Upton Counties, and 1,320 foot spacing between wells in all other counties and horizons. The ultimate inter-well spacing may be less than these amounts, which would result in a higher location count. Based on horizontal wells drilled to date, we currently estimate that EURs for our Wolfcamp B

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horizontal wells will be approximately 550 to 650 MBOE for lateral lengths averaging 7,500 feet. 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 approximately 24 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 the date of this prospectus, we had no borrowings outstanding under our revolving credit facility and available borrowing capacity of $180.0 million. We expect that our borrowing base will be further increased as we increase our reserves.

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 49,861 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 54,035 net acres at June 30, 2013. Since our initial acquisition in the Permian Basin through June 30, 2013, we drilled or participated in the drilling of 249 gross (216 net) wells on our leasehold in this area, primarily targeting the Wolfberry play. We are the operator of approximately 99% of our Permian Basin acreage. 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. As discussed in more detail under "—Recent Developments—Pending Acquisitions," we have entered into agreements to acquire approximately 11,150 additional net acres in the Permian Basin.

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. 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

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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 June 30, 2013, we held interests in 274 gross (242 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 prospectus, 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, 2012, net production from our Permian Basin acreage was 1,078,320 BOE, or an average of 2,946 BOE/d, of which 70% was oil, 17% was natural gas liquids and 13% was natural gas. During the six months ended June 30, 2013, our average daily production was approximately 5,694 BOE, of which 73% was oil, 15% was natural gas liquids and 12% was natural gas.

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.

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Future Activity

During 2013, we expect to drill an estimated 38 gross (33 net) vertical wells and 33 gross (30 net) horizontal wells on our acreage. We currently estimate that our capital expenditures for 2013 will be between $290.0 million and $320.0 million, which includes costs for infrastructure and non-operated wells but does not include the cost of any land acquisitions. During the six months ended June 30, 2013, we drilled 24 gross (20.5 net) vertical wells and 14 gross (12.5 net) horizontal wells and participated in the drilling of one gross (0.4 net) non-operated well in the Permian Basin. During the six months ended June 30, 2013, our aggregate capital expenditures for drilling and infrastructure were $112.1 million, and we spent an additional $6.2 million for leasehold acquisitions.

Oil and Natural Gas Data

Proved Reserves

SEC Rule-Making Activity

In December 2008, the 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 were prepared by Ryder Scott as of December 31, 2012 and 2011 and by Pinnacle as of December 31, 2010, in each case with respect to our assets in the Permian Basin.

Each of Ryder Scott and Pinnacle 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. Neither independent third-party engineering firm owns an interest in any of our properties or is 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 2012 proved reserves 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 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

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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 and the present value of our reserves as of December 31, 2012 and 2011, based on the reserve report prepared by Ryder Scott, and as of December 31, 2010, based on the reserve report prepared by Pinnacle, each an independent petroleum engineering firm, and such reserve reports have been prepared in accordance with the rules and regulations of the SEC. All our proved reserves included in the reserve reports are located in North America. Ryder Scott and Pinnacle prepared all our reserve estimates as of the periods covered by their respective reports.

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	Historical Year Ended December 31, 2012	2011	2010
Estimated proved developed reserves:			
Oil (Bbls)	7,189,367	3,949,099	3,371,460
Natural gas (Mcf)	12,864,941	5,285,945	4,336,720
Natural gas liquids (Bbls)	2,999,440	1,263,710	1,126,431
Total (BOE)	12,332,964	6,093,800	5,220,678
Estimated proved undeveloped reserves:			
Oil (Bbls)	19,007,492	14,151,337	16,258,700
Natural gas (Mcf)	21,705,207	15,265,522	18,358,360
Natural gas liquids (Bbls)	5,251,989	3,785,849	4,706,536
Total (BOE)	27,877,016	20,481,440	24,024,963
Estimated Net Proved Reserves:			
Oil (Bbls)	26,196,859	18,100,436	19,630,160
Natural gas (Mcf)	34,570,148	20,551,467	22,695,080
Natural gas liquids (Bbls)	8,251,429	5,049,559	5,832,967
Total (BOE)[1]	40,209,979	26,575,240	29,245,641
Percent proved developed	30.7 %	22.9 %	17.9 %

(1) Estimates of reserves as of December 31, 2012, 2011 and 2010 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, 2012, 2011 and 2010, respectively, in accordance with revised SEC guidelines applicable to reserve 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 “Risk Factors” beginning on page 15 of this prospectus. 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.

Additional information regarding our proved reserves can be found in the reserve report as of December 31, 2012 included as Appendix B to this prospectus.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2012, our proved undeveloped reserves totaled 19,008 MBbls of oil, 21,705 MMcf of natural gas and 5,251 MBbls of natural gas liquids, for a total of 27,877 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Changes in PUDs that occurred during 2012 were primarily due to:

- additions of 3,167 MBOE attributable to extensions resulting from strategic drilling of wells by us to delineate our acreage position;
- the conversion of approximately 3,224 MBOE attributable to PUDs into proved developed reserves;
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negative revisions of approximately 625 MBOE in PUDs due to a combination of lower product prices causing wells to reach economic limit earlier, adjustments in working interest and performance revisions; and

- purchases of reserves in place of 8,077 MBOE.

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Costs incurred relating to the development of PUDs were approximately $50.2 million during 2012. Estimated future development costs relating to the development of PUDs are projected to be approximately $135.8 million in 2013, $132.0 million in 2014, $154.8 million in 2015, $97.9 million in 2016 and $20.0 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 2017.

As of December 31, 2012, 1.2% 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				
	Six Months Ended June 30,		Year Ended December 31,		
	2013	2012	2012	2011	2010
Production Data:					
Oil (Bbls)	748,244	317,906	756,286	449,434	280,721
Natural gas (Mcf)	759,568	290,171	833,516	413,640	323,847
Natural gas liquids (Bbl)	155,689	65,188	183,114	86,815	79,978
Combined volumes (BOE)	1,030,528	431,456	1,078,320	605,189	414,674
Daily combined volumes (BOE/d)	5,694	2,371	2,946	1,658	1,136
Average Prices(1):					
Oil (per Bbl)	$88.59	$91.26	$86.88	$92.24	$76.51
Natural gas (per Mcf)	3.71	2.27	2.85	3.98	4.32
Natural gas liquids (per Bbl)	33.38	41.59	37.57	54.98	44.56
Combined (per BOE)	72.10	75.05	69.52	79.11	63.77
Average Costs (per BOE):					
Lease operating expense	$11.18	$14.64	$15.57	$17.51	$11.07
Gathering and transportation expense	$0.37	$0.34	$0.39	$0.33	$0.26
Production taxes	$3.52	$3.66	$3.42	$3.91	$3.25
Production taxes as a % of sales	4.9 %	4.9 %	4.9 %	4.9 %	5.1 %
Depreciation, depletion and amortization	$24.80	$24.14	$24.36	$25.78	$19.64
General and administrative	$4.94	$6.58	$9.62	$6.04	$7.32

(1) After giving effect to our hedging arrangements, the average prices per Bbl of oil and per BOE were $85.38 and $69.77, respectively, during the six months ended June 30, 2013, $80.34 and $67.00, respectively, during the six months ended June 30, 2012, $79.68 and $64.47, respectively, during the year ended December 31, 2012, and $92.15 and $79.05, respectively, during the year ended December 31, 2011. Average prices for our hydrocarbons were not impacted by hedging arrangements during 2010.

Productive Wells

As of June 30, 2013, we owned an average 88% working interest in 274 gross (242 net) productive wells. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

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Acreage

The following table sets forth information as of June 30, 2013 relating to our leasehold acreage:

	Developed Acreage[(1)]		Undeveloped Acreage[(2)]		Total Acreage	
Basin	Gross[(3)]	Net[(4)]	Gross[(3)]	Net[(4)]	Gross[(3)]	Net[(4)]
Permian	10,520	8,969	51,187	45,066	61,707	54,035

(1) Developed acres are acres spaced or assigned to productive wells and do not include undrilled acreage held by production under the terms of the lease.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Undeveloped acreage expirations

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. The following table sets forth the gross and net undeveloped acreage, as of December 31, 2012, that will expire over the next five years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2013		2014		2015		2016		2017	
Basin	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian	759	581	2,651	2,157	20,835	17,286	6,893	6,893	2,626	1,820

Drilling Results

The following table sets forth information with respect to the number of wells completed during the periods indicated. Each of these wells was drilled in the Permian Basin of West Texas. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Year Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	44	28	39	23	41	27
Dry	—	—	—	—	—	—
Exploratory:						
Productive	14	7	7	4	—	—
Dry	—	—	—	—	—	—
Total:						
Productive	58	35	46	27	41	27
Dry	—	—	—	—	—	—

As of December 31, 2012, we had 20 gross (16.3 net) wells in the process of drilling, completing or dewatering or shut in awaiting infrastructure that are not reflected in the above table.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Marketing and Customers

We market the majority of the oil and natural gas production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our natural gas production to purchasers at market prices. In March 2009, we entered into an agreement with Windsor Midstream LLC, or Midstream, an entity controlled by Wexford, our equity sponsor. During 2010 and 2011, Midstream purchased a significant portion of our oil volumes. Effective December 1, 2011 we ceased all sales of our production under this agreement and effective January 1, 2012 the agreement was canceled. We sell all of our natural gas under contracts with terms of greater than twelve months and all of our oil under contracts with terms of twelve months or less, excluding a five year oil purchase agreement with Shell Trading (US) Company, or Shell Trading, described below.

We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the six months ended June 30, 2013, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (53%); Shell Trading (US) Company (15%); and Occidental Energy Marketing, Inc. (14%). For the year ended December 31, 2012, three purchasers each accounted for more than 10% of our revenue: Plains Marketing, L.P. (53%); Occidental Energy Marketing, Inc. (16%); and Andrews Oil Buyers, Inc. (10%). For the years ended December 31, 2011 and 2010, one purchaser, Midstream, accounted for approximately 79% of our revenue in both periods. No other customer accounted for more than 10% of our revenue during these periods. If a major customer decided to stop purchasing oil and natural gas from us, revenue could decline and our operating results and financial condition could be harmed. However, based on the current demand for oil and natural gas, and the availability of other purchasers, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition and results of operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

On May 24, 2012, we entered into an oil purchase agreement with Shell Trading, in which we agreed to sell specified quantities of oil to Shell Trading. We are obligated to commence delivery of our oil to Shell Trading upon completion of the reversal of the Magellan Longhorn pipeline and its conversion for oil shipment, which we refer to as the completion date, which is currently anticipated to occur during the third quarter of 2013, although earlier, prorated delivery into the pipeline has begun as the pipeline has commenced line fill and start up operations. We delivered approximately 1,224 gross barrels of oil per day into the pipeline in June 2013 and anticipate additional pro-rated monthly deliveries until reaching full pipeline capacity in late 2013. Our agreement with Shell Trading has an initial term of five years from the completion date. Each party has the right to terminate the agreement by written notice to the other party without any obligations to the other party in the event that the completion date does not occur by January 15, 2014. The agreement may also be terminated by Shell Trading by written notice to us in the event that Shell Trading's contract for transportation on the pipeline is terminated.

Our maximum delivery obligation under this agreement is 8,000 gross barrels per day. We have a one-time right to elect to decrease the contract quantity by not more than 20% of the then-current quantity, which decreased contract quantity will be effective for the remainder of the term of the agreement. Shell Trading has agreed to pay to us the price per barrel of oil based on the arithmetic average of the daily settlement price for "Light Sweet Crude Oil" Prompt Month future contracts reported by the New York Mercantile Exchange over the one-month period, as adjusted based on adjustment formulas specified in the agreement. If we fail to deliver the required quantities of oil under the agreement during any three-month period following the service commencement date, we have agreed to pay Shell Trading a deficiency payment, which is calculated by multiplying (i) the volume of oil that we failed to deliver as required under the agreement during such period by (ii) Magellan's Longhorn Spot tariff rate in effect for transportation from Crane, Texas to the Houston Ship Channel for the period of time for which such deficiency volume is calculated.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties. Further, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Transportation

During the initial development of our fields we consider all gathering and delivery infrastructure in the areas of our production. Our oil is transported from the wellhead to our tank batteries by our gathering systems. The oil is then transported by the purchaser by truck to a tank farm where it is further transported by pipeline. Our natural gas is generally transported from the wellhead to the purchaser’s pipeline interconnection point through our gathering system. During the fourth quarter of 2012, we completed construction of a gas gathering system that transports our gas stream to a sour gas pipeline, thereby eliminating the processing and treating expense. In addition, in the first quarter of 2013, we began moving a portion of our produced water by a pipeline connected to a commercial salt water disposal well rather than by truck, and as of July 2013 we were moving a majority of our produced water by pipeline. During the remainder of 2013, we intend to continue the migration of water disposal and oil transportation from truck carriers to pipelines. We believe that the completion of gathering systems, the connection to salt water disposal wells and other actions will help us to reduce our lease operating expense in future periods.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 18.75% to 25.00%, resulting in a net revenue interest to us generally ranging from 81.25% to 75.00%.

Seasonal Nature of Business

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

Regulation

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability.

Environmental Matters and Regulation

Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous

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governmental agencies, such as the U.S. Environmental Protection Agency, or the EPA, issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

Waste Handling. The Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute “solid wastes” that are subject to the less stringent requirements of non-hazardous waste provisions. However, we cannot assure you that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as “hazardous wastes.” Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or the “Superfund” law, and analogous state laws, generally imposes strict and joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed “responsible parties” may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such "hazardous substances" have been released.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the "Clean Water Act," the Safe Drinking Water Act, the Oil Pollution Act, or OPA, and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including

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jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on October 20, 2011, the EPA announced a schedule to develop pre-treatment standards for wastewater discharges produced by natural gas extraction from underground coalbed and shale formations. The EPA stated that it will gather data, consult with stakeholders, including ongoing consultation with industry, and solicit public comment on a proposed rule for coalbed methane in 2013 and a proposed rule for shale gas in 2014. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, on August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new emission controls for oil and natural gas production and processing operations, which regulations are discussed in more detail below in "—Regulation of Hydraulic Fracturing." These laws and regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects.

Climate Change. In December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule, which purports to limit emissions of GHGs from motor vehicles manufactured in model years 2012 – 2016, in April 2010 and it became effective in January 2011. A recent rulemaking proposal by the EPA and the Department of Transportation's National Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017-2025. The EPA adopted the stationary source rule, also known as the "Tailoring Rule," in May 2010, and it also became effective in January 2011. The Tailoring Rule establishes new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In addition, the EPA has continued to adopt GHG regulations of other industries, such as the March 2012 proposed GHG rule restricting future development of coal-fired power plants. The proposed rule underwent an extended public comment process, which concluded on June 25, 2012. The EPA is also under a legal obligation pursuant to a consent decree with certain environmental groups to issue new source performance standards for refineries. The EPA is also considering additional regulation of greenhouse gases as "air pollutants." As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of such allowances is expected to escalate significantly.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry. Currently, while we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business.

In addition, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Regulation of Hydraulic Fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, program. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. The EPA, however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as "Class II" UIC wells. At the same time, the White House Council on Environmental Quality is coordinating an administration—wide review of hydraulic fracturing practices and the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress.

On August 16, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules will require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were

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also filed. The EPA intends to issue revised rules in 2013 that are likely responsive to some of these requests. For example, on April 12, 2013, the EPA published a proposed amendment extending compliance dates for certain storage vessels. The final revised rules could require modifications to our operations or increase our capital and operating costs without being offset by increased product capture. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013 that would update existing regulation for hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts, the results of which are expected between later in 2013 and 2014. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural-gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shale formations by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

Several states, including Texas, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission has adopted rules and regulations implementing this legislation that will apply to all wells for which the Railroad Commission issues an initial drilling permit on or after February 1, 2012. The new law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Other Regulation of the Oil and Natural Gas Industry

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

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory

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Commission, or FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

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

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

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

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent

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regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

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

Oil Sales and Transportation. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

State Regulation. Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Operational Hazards and Insurance

The oil business involves a variety of operating risks, including the risk of fire, explosions, blow outs, pipe failures and, in some cases, abnormally high pressure formations which could lead to environmental hazards such as oil spills, natural gas leaks and the discharge of toxic gases. If any of these should occur, we could incur legal defense costs and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies for onshore property (oil lease property/production equipment) for selected locations, rig physical damage protection, control of well protection for selected wells, comprehensive general liability, commercial automobile, workers compensation, pollution liability (claims made coverage with a policy retroactive date), excess umbrella liability and other coverage.

Our insurance is subject to exclusion and limitations, and there is no assurance that such coverage will fully or adequately protect us against liability from all potential consequences, damages and losses. Any of these operational hazards could cause a significant disruption to our business. A loss not fully covered by insurance could have a material adverse affect on our financial position, results of operations and cash flows. See “Risk Factors—Risks Related to the Oil and Natural Gas Industry and Our Business—Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits” on page 29 of this prospectus.

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We reevaluate the purchase of insurance, policy terms and limits annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

Generally, we also require our third party vendors to sign master service agreements in which they agree to indemnify us for injuries and deaths of the service provider's employees as well as contractors and subcontractors hired by the service provider.

Employees

As of June 30, 2013, we had approximately 62 full time employees. None of our employees are represented by labor unions or covered by any collective bargaining agreements. We also hire independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist our full time employees.

Facilities

Our corporate headquarters is located in Midland, Texas. We also lease additional office space in Midland and in Oklahoma City, Oklahoma. We believe that our facilities are adequate for our current operations.

Legal Proceedings

In September 2010, Windsor Permian (now known as Diamondback O&G LLC) purchased certain property in Goodhue County, Minnesota from Scott and Susan Wesch that was prospective for hydraulic fracturing grade sand. Prior to this purchase, Scott and Susan Wesch had entered into a Mineral Development Agreement with Robert Stein, and Windsor Permian purchased the property subject to that agreement. Windsor Permian subsequently contributed the property to Muskie. In an amended complaint filed in November 2012 by Robert Stein against Scott and Susan Wesch, Windsor Permian and certain affiliates of Windsor Permian in the first judicial district court in Goodhue County, Minnesota, Stein seeks damages from Windsor Permian and the other defendants alleging, among other things, interference with contractual relationship, interference with prospective advantage and unjust enrichment. In an order filed on May 24, 2013, the judge denied certain motions made by the defendants and set a trial date to determine liability, with a damage phase of the matter to commence on a later date if there is a determination of liability. Following a trial on the liability phase on June 21, 2013, the jury determined that the defendants intentionally interfered with plaintiff's contract but that the interference did not cause the plaintiff to be unable to acquire mining permits prior to the enactment of a frac sand mining moratorium by Goodhue County. In an order filed on July 10, 2013, the judge ordered the damage phase to be set for trial following a pretrial and scheduling conference set for August 12, 2013. We believe these claims are without merit and will continue to vigorously defend this action. While management has determined that the possibility of loss is remote, litigation is inherently uncertain and management cannot determine the amount of loss, if any, that may result.

We could be subject to various possible loss contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Management believes it has complied with the various laws and regulations, administrative rulings and interpretations.

Due to the nature of our business, we are, from time to time, involved in other routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment related disputes. In the opinion of our management, none of these other pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

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MANAGEMENT

Executive Officers and Directors

Set forth below is the name, age, position and a brief account of the business experience of each of our executive officers and directors as of June 30, 2013.

Name	Age	Position
Travis D. Stice	51	Chief Executive Officer, Director
Teresa L. Dick	43	Chief Financial Officer, Senior Vice President
Russell Pantermuehl	53	Vice President — Reservoir Engineering
Paul Molnar	57	Vice President — Geoscience
Michael Hollis	38	Vice President — Drilling
William Franklin	58	Vice President — Land
Jeff White	57	Vice President — Operations
Randall J. Holder	60	Vice President, General Counsel and Secretary
Steven E. West	52	Director
Michael P. Cross	61	Director
David L. Houston	60	Director
Mark L. Plaumann	57	Director

Travis D. Stice—Chief Executive Officer—Mr. Stice has served as our Chief Executive Officer since January 2012 and as a director of our Company since November 2012. Prior to his current position with us, he served as our President and Chief Operating Officer from April 2011 to January 2012. Mr. Stice has also served on the board of managers of MidMar Gas LLC, or MidMar, an entity that owns a gas gathering system and processing plant, since 2011 and as Vice President and Secretary of MidMar since April 2012. From November 2010 to April 2011, Mr. Stice served as a Production Manager of Apache Corporation, an oil and gas exploration company. Mr. Stice served as a Vice President of Laredo Petroleum Holdings, Inc, an oil and gas exploration company, from September 2008 to September 2010. From April 2006 until August 2008, Mr. Stice served as a Development Manager of ConocoPhillips/Burlington Resources Mid-Continent Business Unit, an oil and gas exploration company. Prior to that, Mr. Stice held a series of positions at Burlington Resources, an oil and gas exploration company, most recently as a General Manager, Engineering, Operations and Business Reporting of its Mid Continent Division from January 2001 until Burlington Resources' acquisition by ConocoPhillips in March 2006. Mr. Stice has over 26 years of industry experience in production operations, reservoir engineering, production engineering and unconventional oil and gas exploration and over 18 years of management experience. Mr. Stice graduated from Texas A&M University with a Bachelor of Science degree in Petroleum Engineering. Mr. Stice is a registered engineer in the State of Texas, and is a 25-year member of the Society of Petroleum Engineers.

Teresa L. Dick—Chief Financial Officer, Senior Vice President—Ms. Dick has served as our Chief Financial Officer and Senior Vice President since November 2009. Prior to her current position with us, Ms. Dick served as our Corporate Controller from November 2007 until November 2009. From June 2006 to November 2007, Ms. Dick held a key management position as the Controller/Tax Director at Hiland Partners, a publicly-traded midstream energy master limited partnership. Ms. Dick has over 19 years of accounting experience, including over eight years of public company experience in both audit and tax areas. Ms. Dick received her Bachelor of Business Administration degree in Accounting from the University of Northern Colorado. Ms. Dick is a certified public accountant and a member of the American Institute of CPAs and the Council of Petroleum Accountants Societies.

Russell Pantermuehl—Vice President—Reservoir Engineering—Mr. Pantermuehl joined us in August 2011 as Vice President—Reservoir Engineering. Prior to his current position with us, Mr. Pantermuehl served as a reservoir engineering supervisor for Concho Resources Inc., an oil and gas exploration company, from March 2010 to August 2011. Mr. Pantermuehl worked for ConocoPhillips Company as a reservoir engineering advisor from January 2005 to March 2010. Mr. Pantermuehl also worked as an independent consultant in the oil and gas industry from March 2000 to December 2004. Mr. Pantermuehl received a Bachelor of Science degree in Petroleum Engineering from Texas A&M University.

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Paul Molnar—Vice President—Geoscience—Mr. Molnar joined us in August 2011 as Vice President—Geoscience. Prior to hi current position with us, Mr. Molnar served as a Senior District Geologist for Samson Investment Company, an oil and gas exploration company, from March 2011 to August 2011. Mr. Molnar worked as an asset supervisor and geosciences supervisor for ConocoPhillips Company from April 2006 to February 2011. Mr. Molnar also worked as a geologic advisor for Burlington Resources, an oil and gas exploration company, from December 1996 to March 2006. Mr. Molnar has over 31 years of industry experience. Mr. Molnar received a Master of Science degree in Geology from The State University of New York at Buffalo, New York.

Michael Hollis—Vice President—Drilling—Mr. Hollis joined us in September 2011 as Vice President—Drilling. Prior to his current position with us, Mr. Hollis served in various roles, most recently as drilling manager at Chesapeake Energy Corporation, an oil and gas exploration company, from June 2006 to September 2011. Mr. Hollis worked for ConocoPhillips Company as a senior drilling engineer from January 2004 to June 2006 and as a process engineer from 2001 to 2003. Mr. Hollis also worked as a production engineer for Burlington Resources from 1998 to 2001 as well as from June 2003 to January 2004. Mr. Hollis received his Bachelor of Science degree in Chemical Engineering from Louisiana State University.

William Franklin—Vice President—Land—Mr. Franklin joined us in August 2011 as Vice President—Land. Prior to his curre position with us, Mr. Franklin worked for ConocoPhillips Company in various land management roles from May 1983 until July 2011. Mr. Franklin received a Bachelor of Arts degree in History from Oklahoma City University.

Jeff White—Vice President—Operations—Mr. White joined us in September 2011 as Vice President—Operations. Prior to his current position with us, Mr. White worked for Laredo Petroleum Holdings, Inc. as a completion manager from May 2010 to September 2011. Mr. White also worked as a staff engineer for ConocoPhillips from February 2007 to May 2009. In addition, he worked in various engineering and management positions with Anadarko Petroleum from June 1988 to June 2005. Mr. White received a Bachelor of Science degree in Petroleum Engineering from Texas Tech University. He also received a Bachelor of Science degree in Fishery Biology from New Mexico State University.

Randall J. Holder—Vice President, General Counsel and Secretary—Mr. Holder joined us in November 2011 as General Counsel and Vice President responsible for legal and human resources. Prior to his current position with us, Mr. Holder served as General Counsel and Vice President for Great White Energy Services LLC, an oilfield services company, from November 2008 to November 2011. Mr. Holder served as Executive Vice President and General Counsel for R.L. Hudson and Company, a supplier of molded rubber and plastic components, from February 2007 to October 2008. Mr. Holder was in private practice of law and a member of Holder Betz LLC from February 2005 to February 2007. Mr. Holder served as Vice President and Assistant General Counsel for Dollar Thrifty Automotive Group, a vehicle rental company, from January 2003 to February 2005 and, before that, as Vice President and General Counsel for Thrifty Rent-A-Car System, Inc., a vehicle rental company, from September 1996 to December 2002. He also served as Vice President and General Counsel for Pentastar Transportation Group, Inc. from November 1992 to September 1996, which was wholly-owned by Chrysler Corporation. Mr. Holder started his legal career with Tenneco Oil Company where he served as a Division Attorney providing legal services to the company's mid-continent division for ten years. Mr. Holder received a Juris Doctorate degree from Oklahoma City University.

Steven E. West—Director—Mr. West has served as a director of our company since December 2011 and Chairman of the Board since October 2012. Mr. West served as our Chief Executive Officer from January 1, 2009 to December 31, 2011. Since January 2011, Mr. West has been a partner at Wexford Capital LP, focusing on Wexford's private equity energy investments. From August 2006 until December 2010, Mr. West served as senior portfolio advisor at Wexford. From August 2003 until August 2006, Mr. West was the chief financial officer of Sunterra Corporation, a former Wexford portfolio company. From December 1993 until July 2003, Mr. West held senior financial positions at Coast Asset Management and IndyMac Bank. Prior to that, Mr. West worked at First Nationwide Bank, Lehman Brothers and Peat Marwick Mitchell & Co., the predecessor of KPMG LLP. Mr. West holds a Bachelor of Science degree in Accounting from California State University, Chico. We believe Mr. West's background in finance, accounting and private equity energy investments, as well as his executive management skills developed as part of his career with Wexford, its portfolio companies and other financial institutions qualify him to serve on our board of directors.

Michael P. Cross—Director—Mr. Cross has served as a director of our company since October 2012. Mr. Cross is President and owner of Michael P. Cross, Inc., an independent oil and natural gas producer, a position he has held since July 1994. Mr. Cross also currently serves as a director of Warren Equipment Company, a position he has held since 2002. Mr. Cross has also served as a member of the Oklahoma Energy Resources Board since February 2005 and has been a member of the Executive Committee since 2007. Mr. Cross also served as a member of the Board of Directors of the Oklahoma Independent Petroleum Association for over 15 years. Mr. Cross served on the Board of Directors for OGE Energy GP LLC from October 2007 to October 2008. Mr. Cross also served as CEO and President of Windsor Energy Resources, Inc. from December 2005 until December 2006. Mr. Cross served as President and Manager of Twister Gas Services, L.L.C., an oil and gas exploration, production and marketing company, from its inception in 1996 until June 2003 and served as President of its predecessor,

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Twister Transmission Company, from 1990 to 1996. Mr. Cross graduated from Oklahoma State University in 1973 with a BS in Business Administration. We believe that Mr. Cross's strong oil and gas background and executive management experience qualify him for service on our board of directors.

David L. Houston—Director—Mr. Houston has served as a director of our company since October 2012. Since 1991, Mr. Houston has been the principal of Houston & Associates, a firm that offers life and disability insurance, compensation and benefits plans and estate planning. Prior to 1991, Mr. Houston was President and Chief Executive Officer of Equity Bank for Savings, F.A., an Oklahoma-based savings bank, and is the former chair of the Oklahoma State Ethics Commission and the Oklahoma League of Savings Institutions. In May 1992, in settlement of administrative litigation (and without any finding or admission of guilt) brought by the U.S. Office of Thrift Supervision against him in his capacity as an executive officer of a thrift institution, Mr. Houston entered into a consent order under which he agreed not to serve as an officer of, or participate in the affairs of, insured depository institutions. The order relates to alleged violations of certain lending practices in early 1990 or before. Mr. Houston served on the board of directors and executive committee of Deaconess Hospital, Oklahoma City, Oklahoma, from January 1993 until December 2008 and is the former chair of the Oklahoma State Ethics Commission and the Oklahoma League of Savings Institutions. Mr. Houston has served as a director of Gulfport since July 1998 and is the chairman of its audit committee. He also served as a director of Bronco Drilling Company from May 2005 until December 2010 and was a member of its audit committee. Mr. Houston received a Bachelor of Science degree in business from Oklahoma State University and a graduate degree in banking from Louisiana State University. We believe that Mr. Houston's financial background and his executive management experience qualify him for service on our board of directors.

Mark L. Plaumann—Director—Mr. Plaumann has served as a director of our company since October 2012. He is currently a Managing Member of Greyhawke Capital Advisors LLC, or Greyhawke, which he co-founded in 1998. Prior to founding Greyhawke, Mr. Plaumann was a Senior Vice President of Wexford Capital LP. Mr. Plaumann was formerly a Managing Director of Alvarez & Marsal, Inc. and the President of American Healthcare Management, Inc. He also was Senior Manager at Ernst & Young LLP. Mr. Plaumann served as a director and audit committee chairman for ICx Technologies, Inc. until October 2010 and currently serves as a director and audit committee chairman of Republic Airways Holdings, Inc., and a director of one private company. Mr. Plaumann also has served as a director, an audit committee chairman and a member of the conflicts committee of the general partner of Rhino Resource Partners LP, a coal operating company, since October 2010. Mr. Plaumann holds an M.B.A. and a B.A. in Business from the University of Central Florida. We believe that Mr. Plaumann's service on the boards of other public companies and his executive management experience, including previous experience as chairman of audit committees, qualifies him for service on our board of directors.

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RELATED PARTY TRANSACTIONS

Our board of directors has adopted a policy regarding related party transactions. Under the policy, the audit committee reviews and approves all relationships and transaction in which we and our directors, director nominees and executive officers and their immediate family members, as well as holders of more than 5% of any class of our voting securities and their immediate family members, have a direct or indirect material interest. The policy provides that, the following do not create a material direct or indirect interest on behalf of the related party and are therefore not related party transactions:

- a transaction involving compensation of directors;
- a transaction involving compensation of an executive officer or involving an employment agreement, severance arrangement, change in control provision or agreement or special supplemental benefit of an executive officer;
- a transaction with a related party involving less than $120,000;
- a transaction in which the interest of the related party arises solely from the ownership of a class of our equity securities and all holders of that class receive the same benefit on a pro rata basis;
- a transaction involving indemnification payments and payments under directors and officers indemnification insurance policies made pursuant to our certificate of incorporation or bylaws or pursuant to any policy, agreement or instrument of the Company or to which the Company is bound; and
- a transaction in which the interest of the related party arises solely from indebtedness of a 5% shareholder or an "immediate family member" of a 5% shareholder.

The policy supplements the conflict of interest provisions in our Code of Business Conduct and Ethics.

Prior to the implementation of this policy and the adoption of our Code of Business Conduct and Ethics, the review and approval of related party transactions was the responsibility of our management, and all of the transactions discussed under "Related Party Transactions" below have been approved by our management, subject to a conflicts of interest policy set forth in our employee handbook, pursuant to which all of our employees must avoid any situations where their personal outside interest could conflict, or even appear to conflict, with the interests of the Company. Although our management believes that the terms of the related party transactions described below are reasonable, it is possible that we could have negotiated more favorable terms for such transactions with unrelated third parties.

Gulfport Transaction and Investor Rights Agreement

On May 7, 2012, we entered into an agreement with Gulfport in which we agreed to acquire from Gulfport, prior to the effectiveness of the registration statement relating to our initial public offering, all of Gulfport's oil and natural gas properties in the Permian Basin in exchange for (i) shares of our common stock representing 35% of our common stock outstanding immediately prior to the closing of our initial public offering and (ii) approximately $63.6 million in the form of a non-interest bearing promissory note that was repaid in full upon the closing of our initial public offering. The Gulfport transaction was completed on October 11, 2012. The aggregate consideration payable to Gulfport was subject to a post-closing cash adjustment calculated to be approximately $18.6 million and paid to Gulfport in January 2013. Under the agreement, Gulfport is generally responsible for all liabilities and obligations with respect to its Permian Basin properties arising prior to the closing of the transaction and we are responsible for such liabilities and obligations arising after the closing of the transaction. At the closing of the Gulfport transaction, we entered into an investor rights agreement with Gulfport in which Gulfport was granted certain (i) demand and "piggyback" registration rights, (ii) director nomination rights and (iii) information rights. Mr. David Houston, one of our directors, was designated by Gulfport in accordance with its director nomination rights. Mike Liddell, who served as the Operating Member and Chairman of our subsidiary Diamondback O&G LLC (formerly known as Windsor Permian LLC) prior to the completion of our initial public offering, was formerly the Chairman of the Board and a director of Gulfport and has a 10% interest in DB Holdings. Charles E. Davidson, the Chairman and Chief Investment Officer of Wexford, beneficially owned approximately 13.3% of Gulfport's outstanding common stock as of December 5, 2011 and approximately 9.5% as of March 13, 2012, which interest was reduced to less than 1% as of September 28, 2012.

Administrative Services

We entered into a shared services agreement, dated March 1, 2008, with Everest Operations Management LLC (formerly, Windsor Energy Resources LLC), or Everest, an entity controlled by Wexford, our equity sponsor. Under this agreement, Everest provided us with administrative and payroll services and office space in Oklahoma City, Oklahoma and we reimbursed Everest in an amount determined by Everest's management based on estimates of the amount of office space provided and the amount of its employees' time spent performing services for us. The reimbursement amounts were determined based upon underlying salary costs of employees performing Company related functions, payroll, revenue or headcount relative to other companies managed by Everest, or specifically identified invoices processed, depending on the nature of the cost. The initial term of the shared services agreement with Everest was two years. Since the expiration of such two-year period on March 1, 2010, the agreement, by its terms, continued on a month-to-month basis. For the years ended December 31, 2012, 2011 and 2010, we incurred total costs to Everest of approximately $4.4 million, $10.1 million and $8.0 million, respectively, and at December 31, 2012, 2011 and 2010, we owed $13,000, $0.8 million and $0.4 million, respectively, to Everest under this shared services agreement. For the six months ended June 30, 2013, we incurred total costs to Everest of approximately $109,000 and, at June 30, 2013, owed approximately $16,000 to Everest under this shared services agreement.

Effective January 1, 2012, we entered into an additional shared services agreement with Everest under which we provide Everest and, at its request, certain of its affiliates with consulting, technical and administrative services, including payroll, human resources administration, accounts payable and treasury services. The initial term of this shared services agreement is two years. Upon expiration of the initial term, the agreement will continue on a month-to-month basis until cancelled by either party upon thirty days' prior written notice. Everest, or its affiliates, reimburse us for our dedicated employee time and administrative costs based on the pro rata share of time our employees spend performing these services, including pro rata benefits and bonuses of such employees. For the six months ended June 30, 2013 and the year ended December 31, 2012, Everest and its affiliates reimbursed us $0.8 million and $2.1 million, respectively, for services and overhead under this shared services agreement and, at June 30, 2013 and December 31, 2012, Everest and its affiliates owed us $0 and $1,000, respectively.

Diamondback O&G LLC

In connection with the completion of our initial public offering, we acquired all of the equity interests in Diamondback O&G LLC (formerly known as Windsor Permian LLC) and Windsor UT from Wexford in exchange for 14,697,496 shares of our common stock. For additional information regarding these transactions, see "Prospectus Summary—Our History" on page 7 of this prospectus.

Subordinated Note

Effective May 14, 2012, we issued a subordinated note to an affiliate of Wexford pursuant to which, as amended, the Wexford affiliate could, from time to time, advance up to an aggregate of $45.0 million. These advances were solely at the lender's discretion and neither Wexford nor any of its affiliates had any commitment or obligation to provide future capital support to us. The note bore interest at a rate equal to LIBOR plus 0.28% or 8% per annum, whichever was lower. Interest was due quarterly in arrears beginning on July 1, 2012. Interest payments were payable in kind by adding such amounts to the principal balance of this note. The unpaid principal balance and all accrued interest on the note were due and payable in full on January 31, 2015 or the earlier completion of our initial public offering. Any indebtedness evidenced by this note was subordinate in the right of payment to any indebtedness outstanding under our revolving credit facility. On September 30, 2012, there was $30.0 million in aggregate principal amount outstanding under this note. We repaid the outstanding borrowings under this note with a portion of the net proceeds of our initial public offering and the note was terminated.

Drilling and Field Services

Bison Drilling and Field Services LLC, or Bison, has performed drilling and field services for us under master drilling agreements and master field services agreements. These agreements are terminable by either party on 30 days' prior written notice, although neither party will be relieved of its respective obligations arising from a drilling contract being performed prior to such termination. Bison was a wholly-owned subsidiary of Diamondback O&G LLC until March 31, 2011, when various entities controlled by Wexford started contributing capital to Bison. These contributions aggregated $11.5 million and ultimately diluted Diamondback O&G LLC's ownership interest to 52.2%. In September 2011, Diamondback O&G LLC sold a 25% interest in Bison to Gulfport for $6.0 million, subject to adjustment. At the time of the transaction, an affiliate of Wexford beneficially owned approximately 13.3% of Gulfport's common stock, but that ownership is now less than 1%. In April 2012, Gulfport increased its ownership interest in Bison to 40%. As a result of these transactions, Diamondback O&G LLC's ownership interest in Bison was reduced to 22%, with the remaining equity interests in Bison held by Gulfport and various entities controlled by Wexford. In June 2012, Diamondback O&G LLC distributed its remaining interest in Bison to its member, which is an entity controlled by Wexford. For the six months ended June 30, 2013 and the years ended December 31, 2012 and

2011, we were billed $9.6 million, $16.0 million and $16.3 million, respectively, by Bison for drilling and field services. We owed $0.7 million, $0.1 million and $0.2 million to Bison as of June 30, 2013, December 31, 2012 and 2011, respectively.

Midland Lease

We occupy our corporate headquarters in Midland, Texas under a five-year lease, effective May 15, 2011, with Fasken Midland, LLC, or Fasken, an entity controlled by an affiliate of Wexford. During the six months ended June 30, 2013 and the years ended December 31, 2012 and 2011, we paid $82,000, $155,000 and $40,000, respectively, to Fasken under this lease. In the second quarter of 2013, we amended this lease agreement to increase the size of the leased premises.The current monthly rent under the lease is $13,000 and will increase to $15,000 on September 1, 2013 and $21,000 on October 1, 2013. Thereafter, the monthly rent will increase approximately 4% annually on June 1 of each year during the remainder of the lease term.

Oklahoma City Lease

We occupy office space in Oklahoma City, Oklahoma under a sixty-seven month lease agreement, effective January 1, 2012, with Caliber Investment Group, LLC, or Caliber, an entity controlled by an affiliate of Wexford. During the six months ended June 30, 2013 and the year ended December 31, 2012, we paid $111,000 and $329,000, respectively, to Caliber under this lease. Effective April 1, 2013, we entered into an amendment to this agreement to increase the size of the leased premises, at which time our monthly base rent increased to $19,000 for the remainder of the lease term. We are also responsible for paying a portion of specified costs, fees and expenses associated with the operation of the premises.

Area of Mutual Interest and Related Agreements

Effective as of November 1, 2007, we and Gulfport entered into an area of mutual interest agreement to jointly acquire oil and gas leases in the Permian Basin. The agreement provides that each party must offer the other party the right to participate in 50% of each such acquisition. We and Gulfport also agreed, subject to certain exceptions, to share third-party costs and expenses in proportion to our and its respective participating interests and pay certain other fees as provided in the agreement. The agreement was terminated upon Gulfport’s contribution to us of its oil and gas properties located in the Permian Basin.

In connection with the area of mutual interest agreement, we, Gulfport and Windsor Energy Group, L.L.C., or Energy Group, an entity controlled by Wexford, as the operator, entered into a joint development agreement, effective as of November 1, 2007, pursuant to which we and Gulfport agreed to develop certain jointly-held oil and gas leases in the Permian Basin and Energy Group agreed to act as the operator under the terms of a joint operating agreement, effective as of November 1, 2007. In the event either we or Gulfport had a majority interest in a prospect (as defined in the development agreement), the majority party could designate the operator of its choice. We and Gulfport agreed to designate Energy Group as the operator with respect to the contract area as provided in the joint operating agreement. As operator of these properties, Energy Group was responsible for the daily operations, monthly operation billings and monthly revenue disbursements for the properties in which we held an interest. Effective February 26, 2010, the agreement with Energy Group was terminated and we became the operator of these properties. For the year ended December 31, 2010, Energy Group billed us approximately $4.4 million and at December 31, 2010 we owed Energy Group approximately $0.07 million for these services. Upon becoming operator effective February 26, 2010, we began providing joint interest billing services. For the years ended December 31, 2012, 2011 and 2010, we billed Gulfport $46.4 million, $56.7 million and $32.4 million, respectively, and we billed an entity controlled by Wexford $2.0 million, $5.3 million and $8.8 million, respectively, for such services. At December 31, 2012, 2011 and 2010, Gulfport owed us $0.7 million, $8.6 million and $5.6 million, respectively, and the Wexford controlled entity owed us zero, $0.4 million and zero, respectively. Our joint development agreement with Gulfport was terminated in October 2012 upon Gulfport’s contribution to us of its oil and gas properties located in the Permian Basin.

Muskie Holdings LLC

During 2011, Diamondback O&G LLC purchased certain assets, real estate and rights in a lease covering land in Wisconsin that is prospective for mining oil and natural gas fracture grade sand for $4.2 million from an unrelated third party. On October 7, 2011, Diamondback O&G LLC contributed these assets, real estate and lease rights to a newly-formed entity, Muskie Holdings LLC, or Muskie (now known as Muskie Proppant LLC), in exchange for a 48.6% equity interest. The remaining equity interests in Muskie were held 25% by Gulfport and 26.4% by entities controlled by Wexford. Through additional contributions from the Wexford controlled entities to Muskie, Diamondback O&G LLC’s equity interest decreased to approximately 33%. In June 2012, Diamondback O&G LLC distributed its remaining interest in Muskie to its member, which is an entity controlled by Wexford. We began purchasing sand from Muskie in March 2013. We incurred costs of $234,000 for the six months ended June 30, 2013.

As of June 30, 2013, we did not owe Muskie any amounts.

MidMar

We are party to a gas purchase agreement, dated May 1, 2009, as amended, with MidMar Gas LLC, or MidMar, an entity that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, MidMar is obligated to purchase from us, and we are obligated to sell to MidMar, all of the gas conforming to certain quality specifications produced from certain of our Permian Basin acreage. Following the expiration of the initial ten-year term, the agreement will continue on a year-to-year basis until terminated by either party on 30 days' written notice. Under the gas purchase agreement, MidMar is

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obligated to pay us 87% of the net revenue received by MidMar for all components of our dedicated gas, including liquid hydrocarbons, and the sale of residue gas, in each case extracted, recovered or otherwise processed at MidMar's gas processing plant, and 94.56% of the net revenue received by MidMar from the sale of such gas components and residue gas, extracted, recovered or otherwise processed at the Chevron Headlee plant. Travis D. Stice, our Chief Executive Officer, has served as a manager on MidMar's board of managers since April 2011 and as Vice President and Secretary of MidMar since April 2012. An entity controlled by Wexford in which Gulfport and certain entities controlled by Wexford are members owns approximately a 28% equity interest in MidMar. The remaining equity interests in MidMar are owned by nonaffiliated third parties. For the years ended December 31, 2012, 2011 and 2010, MidMar paid us $3.0 million, $3.1 million and $1.1 million, respectively, and at December 31, 2012, 2011 and 2010, MidMar owed us zero, $0.5 million and $0.1 million, respectively, for our portion of the net proceeds from the sale of such gas products and residue gas by MidMar. For the six months ended June 30, 2013, MidMar paid us $2.8 million and, at June 30, 2013, MidMar owed us $0.5 million for our portion of the net proceeds from the sale of such gas products and residue gas by MidMar.

Advisory Services Agreement

During the period January 1, 2012 through October 11, 2012, Wexford provided certain professional services to us, for which we were billed approximately $0.1 million. On October 11, 2012, we entered into an advisory services agreement with Wexford under which Wexford agreed to provide us with general financial and strategic advisory services related to our business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. This agreement has a term of two years and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. The agreement may be terminated at any time by either party upon 30 days' prior written notice. In the event we terminate the agreement, we are obligated to pay all amounts due through the remaining term of the agreement. In addition, under the terms of the agreement we have agreed to pay Wexford to-be-negotiated market-based fees approved by our independent directors for such services as may be provided by Wexford at our request in connection with future acquisitions and divestitures, financings or other transactions. The services provided by Wexford under the advisory services agreement will not extend to our day-to-day business or operations. In this agreement, we have agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct. We incurred total costs of $0.3 million and $0.2 million during the six months ended June 30, 2013 and the year ended December 31, 2012, respectively, under this advisory services agreement and, as of June 30, 2013 and December 31, 2012, we owed Wexford $0 and $0.1 million, respectively, under this agreement. We did not incur any costs for professional services from Wexford during the years ended December 31, 2011 and 2010.

Registration Rights

We have entered into a registration rights agreement with DB Holdings and an investor rights agreement with Gulfport. Under these agreements, each of DB Holdings and Gulfport has certain demand and "piggyback" registration rights. For more information regarding these agreements, see "—Gulfport Transaction and Investor Rights Agreement" and "Shares Eligible for Future Sale—Registration Rights" on pages 73 and 84, respectively, of this prospectus. The June 2013 secondary offering was undertaken pursuant to these registration rights. We incurred estimated costs of approximately $179,000 in connection with such offering.

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PRINCIPAL STOCKHOLDERS

The following table sets forth certain information with respect to the beneficial ownership of our common stock as of August 1, 2013 by:

- each stockholder known by us to be the beneficial owner of more than five percent of the outstanding shares of our common stock;
- each of our directors;
- each of our named executive officers; and
- all of our directors and executive officers as a group.

Except as otherwise indicated, we believe that each of the stockholders named in this table has sole voting and investment power with respect to the shares indicated as beneficially owned.

Name of Beneficial Owner	Shares Beneficially Owned Prior to Offering[1]			Shares Beneficially Owned After Offering[1]			Shares Beneficially Owned After Offering if Option to Purchase Additional Shares Is Exercised in Full		
	Number	Percentage		Number	Percentage		Number	Percentage	
5% Stockholders:									
DB Energy Holdings LLC[2]	11,092,717	26.3	%	11,092,717	24.0	%	11,092,717	23.7	%
Gulfport Energy Corporation[3]	5,679,500	13.5	%	5,679,500	12.3	%	5,679,500	12.1	%
Wellington Management Company, LLP[4]	3,747,150	8.9	%	3,747,150	8.1	%	3,747,150		