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

FORM 10-K

☒ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2012

OR

☐ **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 001-35700

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

Delaware	**45-4502447**
(State or Other Jurisdiction of Incorporation or Organization)	**(IRS Employer Identification Number)**
500 West Texas, Suite 1225 Midland, Texas	**79701**
(Address of Principal Executive Offices)	**(Zip Code)**

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

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

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

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

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

Large Accelerated Filer	☐	Accelerated Filer	☐
Non-Accelerated Filer	x	Smaller Reporting Company	☐

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

As of June 30, 2012, the last business day of the registrant's most recently completed second fiscal quarter, there was no public market for the registrant's common stock. The registrant's common stock began trading on the NASDAQ Global Select Market on October 12, 2012.

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of December 31, 2012 based on the closing price of the common stock on the NASDAQ Global Select Market on December 31, 2012 ($19.12 per share) was $393,334,919.

As of February 22, 2013, 36,986,532 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Diamondback Energy, Inc.'s Proxy Statement for the 2013 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

DIAMONDBACK ENERGY, INC.
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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

Basin-centered gas. A regional abnormally-pressured, gas-saturated accumulation in low-permeability reservoirs.

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

Bbls/d. Bbls per day.

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

BOE/d. BOE per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Coalbed methane (CBM). Natural gas formed as a byproduct of the coal formation process, which is trapped in coal seams and produced by non-traditional means.

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

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

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

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

Deviated well. A well purposely deviated from the vertical using controlled angles to reach an objective location other than directly below the surface location.

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

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

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

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

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

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

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

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

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

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

PDP. Proved developed producing.

Play. A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

PUD. Proved undeveloped.

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

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Stratigraphic play. An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.

Structural play. An oil or natural gas formation contained within an area created by earth movements that deform or rupture (such as folding or faulting) rock strata.

Tight formation. A formation with low permeability that produces natural gas with very low flow rates for long periods of time.

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

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Workover. The repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this annual report on Form 10-K, could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

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

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

PART I

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

ITEM 1. BUSINESS

Overview

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

We began operations in December 2007 with our acquisition of 4,174 net acres with production at the time of acquisition of approximately 800 BOE/d from 34 gross (16.8 net) wells in the Permian Basin. Subsequently, we acquired approximately 47,429 additional net acres, which brought our total net acreage position in the Permian Basin to 51,603 net acres at December 31, 2012. We are the operator of approximately 99% of this acreage. As of December 31, 2012, we had drilled 193 gross (176 net) wells, and participated in an additional 18 gross (eight net) non-operated wells, in the Permian Basin. Of these 211 gross wells, 191 were completed as producing wells and 20 were in various stages of completion. In the aggregate, as of December 31, 2012, we held interests in 225 gross (201 net) producing wells 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 881 identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data as of December 31, 2012, and we have an additional 1,118 identified potential vertical drilling locations based on 20-acre downspacing. We have also identified 731 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. Our estimated ultimate recoveries, or EURs, from future PUD 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.

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 24-hour initial production rate of 618 BOE/d and a 30-day average initial production rate of 486 BOE/d, of which 86% was oil. Through the end of 2012, the Janey 16H had produced a total of 48 MBbls of oil and 62 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 with a 3,733 foot lateral. The production as reported to us by the operator was a peak 24 hour rate of 892 BOE/d and peak 30 day rate of 712 BOE/d, of which 85% was oil. Through the end of 2012, the Kemmer 4209H had produced a total of 41 MBbls of oil and 45 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.

In addition to the Janey and Kemmer wells, as of February 28, 2013 we had three additional horizontal wells in Midland County and four horizontal wells in Upton County in various stages of development. In Midland County, we have drilled the ST25-1H well (83% working interest) with a lateral length of 4,617 feet and are currently drilling the ST25-2H well (83% working interest) with a targeted lateral length of 4,800 feet. We have scheduled a 19 stage hydraulic fracturing operation for each of these wells, with the frac on the ST25-1H well expected to begin in early March 2013 and the frac on the ST25-2H well scheduled immediately after that in mid-March. Also in Midland County, we are participating in the Sarah Ann 3812H, which is a non-operated well in which we have a 42% working interest. It was drilled to a lateral length of 4,461 feet targeting the Wolfcamp B interval and recently completed an 18 stage frac.

In Upton County, we have drilled three additional wells, the Neal 8-1H (100% working interest) with a lateral length of 7,652 feet, the Neal 8-2H (100% working interest) with a lateral length of 6,658 feet and the Janey 3H (100% working interest) with a lateral length of 4,629 feet. We completed a 32 stage frac on the Neal 8-1H well in late January 2013. As of February 26, 2013, flowback operations were underway and for the last seven days the well averaged 806 BOE/d with a peak rate of 871 BOE/d with an 85% oil component. A 28 stage frac is scheduled to begin on the Neal 8-2H well by mid-March 2013. The Janey 3H is currently undergoing a 19 stage frac and is expected to begin flowback in early March. In addition, we are currently drilling the Kendra 1H well in Upton County with a planned 7,550 foot lateral.

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. Based on the data we have, we also believe that a large percentage of our other Midland Basin acreage is prospective for horizontal drilling. This includes not only the Wolfcamp B interval but other intervals ranging from the Clearfork to the Atoka. However, further testing of these areas and other intervals is necessary to determine their economic potential.

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 December 31, 2012, we had 881 identified potential vertical drilling locations on our acreage in the Permian Basin based on 40-acre spacing and an additional 1,118 such locations based on 20-acre downspacing. We were using two vertical drilling rigs as of February 28, 2013.

- **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. Our next two horizontal wells were drilled in Upton County with lateral lengths of 7,652 and 6,685 feet, respectively. In the future, we expect that our optimal average lateral lengths will be in the range of 7,500 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. 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 two horizontal drilling rigs as of February 28, 2013.

- **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 20 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. 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. In addition, 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. Additionally, 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 87% working interest in our acreage allows us to realize the majority of the benefits of these expected improvements 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 intend to continue to pursue acquisitions that meet our strategic and financial targets.

- **Maintain financial flexibility**. We seek to maintain a conservative financial position. Upon completion of our initial public offering in October 2012, we used a portion of the net proceeds from the offering to repay the entire balance outstanding under our revolving credit facility. On December 28, 2012, the borrowing base under our revolving credit facility was redetermined, resulting in an increase in our availability to $135.0 million, of which the entire balance was fully available as of December 31, 2012.

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 was approximately 70% oil, 17% natural gas liquids and 13% natural gas for the year ended December 31, 2012. As of December 31, 2012, our estimated net proved reserves were comprised of approximately 65% oil and 21% natural gas liquids. This oil and liquids exposure allows us to benefit from their currently more favorable prices as compared to natural gas.

- **Multi-year drilling inventory in one of North America's leading oil resource plays**. We have identified a multi-year inventory of potential drilling locations for our oil-weighted reserves that we believe provides attractive growth and return opportunities. As of December 31, 2012, we had 881 identified potential vertical drilling locations based on 40-acre spacing and an additional 1,118 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 731 potential horizontal locations on our acreage. These locations exist across most of our acreage blocks and in multiple horizons. Of the 731 locations, 355 are in the Wolfcamp A horizon or the Wolfcamp B horizon, with the remaining locations in either the Clearfork, Wolfcamp C or Cline horizons. We have not assigned any horizontal locations to the Spraberry interval but believe that it may also have development potential. Our current horizontal location count is based on 1,320 foot spacing between wells. The ultimate inter-well spacing may be closer than 1,320 feet, which would result in a higher location count. 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 December 31, 2012, we had no outstanding borrowings under our revolving credit facility and $135.0 million of available borrowing capacity. We expect that our borrowing base will be increased as we increase our reserves.

Our History

Diamondback Energy, Inc., or Diamondback, was incorporated in Delaware on December 30, 2011, and did not conduct any material business operations until October 11, 2012 when Diamondback merged with its parent entity, Diamondback Energy LLC, with Diamondback continuing as the surviving entity. Prior to the merger, Diamondback Energy LLC was a holding company and did not conduct any material business operations other than its ownership of Diamondback's common stock and the membership interests in Windsor Permian LLC, or Windsor Permian. As a result of the merger, Windsor Permian became a wholly-owned subsidiary of Diamondback. Also on October 11, 2012, Wexford Capital LP, or Wexford, our equity sponsor, caused all of the outstanding equity interests in Windsor UT LLC, or Windsor UT, to be contributed to Windsor Permian prior to the merger in a transaction we refer to as the "Windsor UT Contribution". 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. See Note 2—Acquisitions to our audited combined consolidated financial statements included elsewhere in this Annual Report on Form 10-K for more information regarding the Gulfport transaction.

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.

Review of Exploration, Exploitation and Development Activities

Permian Basin

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 47,429 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 51,603 net acres at December 31, 2012. Since our initial acquisition in the Permian Basin through December 31, 2012, we drilled or participated in the drilling of 211 gross (184 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.

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 formation. Henry Petroleum, a private firm, owned interests in the Pegasus field in Midland and Upton counties. While drilling in the same area as the Arco project, Henry Petroleum decided to drill completely through the Wolfcamp section. Henry Petroleum mapped the trend and began acquiring acreage and drilling wells using multiple slick-water fracturing treatments across the entire Wolfcamp interval. In 2005, former members of Henry Petroleum's Wolfcamp team formed their own private company, ExL Petroleum, and began replicating Henry Petroleum's program. After ExL had drilled 32 productive Wolfcamp/Spraberry wells through late 2007, they monetized a portion of their acreage position, which led to the acquisition that enabled us to begin our participation in this play. Recent advancements in enhanced recovery techniques and horizontal drilling continue to make this play attractive to the oil and gas industry. By mid-2010, approximately half of the rigs active in the Permian Basin were drilling wells in the Wolfberry play. As of December 31, 2012, we held interests in 225 gross (201 net) producing wells.

Geology

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

The Wolfberry play can be generally characterized as a combination of low-permeability clastic, carbonate and shale reservoirs which are hydrocarbon-charged and are economic due to the overall thickness of the section (more than 3,000 feet) and application of enhanced stimulation (fracking) techniques. The Wolfberry is an unconventional "basin-centered oil" resource play, in the sense that there is no regional downdip oil/water contact. Several shale intervals within the Wolfcamp formation are currently being evaluated for horizontal development potential, and initial drilling to explore these intervals commenced in 2012. The shales exhibit micro-darcy permeabilities which result in relatively small drainage areas and recovery factors. Because of this, we believe the horizontal exploitation of these reservoirs will supplement, and not replace, our vertical development program.

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

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

Production Status

During the year ended December 31, 2012, net production from our Permian Basin acreage was 1,078,321 BOE, or an average of 2,946 BOE/d, of which 70% was oil, 17% was natural gas liquids and 13% 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.

Future Activity

During 2013, we expect to drill an estimated 37 gross (31 net) vertical wells and 25 gross (22 net) horizontal wells on our acreage. We estimate that our capital expenditures for 2013 will be between $270 million and $300 million, which includes costs for infrastructure and non-operated wells but does not include the cost of any land acquisitions.

Oil and Gas Data

Proved Reserves

SEC Rule-Making Activity

In December 2008, the Securities and Exchange Commission, or 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 Energy Services, LLC, or 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 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.

	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 reserves estimates as of the end of such periods. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

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

Proved Undeveloped Reserves (PUDs)

As of December 31, 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;
- 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.

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 $136.8 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 Gas Production Prices and Production Costs

Production and Price History

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

	Historical		
	Year Ended December 31,		
	2012	2011	2010
Production Data:			
Oil (Bbls)	756,286	449,434	280,721
Natural gas (Mcf)	833,516	413,640	323,847
Natural gas liquids (Bbl)	183,114	86,815	79,978
Combined volumes (BOE)	1,078,320	605,189	414,674
Daily combined volumes (BOE/d)	2,946	1,658	1,136
Average Prices[(1)]:			
Oil (per Bbl)	$ 86.88	$ 92.24	$ 76.51
Natural gas (per Mcf)	2.85	3.98	4.32
Natural gas liquids (per Bbl)	37.57	54.98	44.56
Combined (per BOE)	69.52	79.11	63.77
Average Costs (per BOE):			
Lease operating expense	$ 15.57	$ 17.51	$ 11.07
Gathering and transportation expense	$ 0.39	$ 0.33	$ 0.26
Production taxes	$ 3.42	$ 3.91	$ 3.25
Production taxes as a % of sales	4.9%	4.9%	5.1%
Depreciation, depletion and amortization	$ 24.36	$ 25.78	$ 19.64
General and administrative	$ 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 $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 December 31, 2012, we owned an average 87.0% working interest in 225 gross (201 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.

Acreage

The following table sets forth information as of December 31, 2012 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	9,560	8,184	49,645	43,419	59,205	51,507

(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 19 gross (15.3 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 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 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 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 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 delivery into the pipeline is anticipated as the pipeline commences line fill and start up operations. 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 delivery obligation under this agreement is 5,000 barrels per day from the service commencement date to March 31, 2013, 6,000 barrels per day from April 1, 2013 to September 30, 2013 and 8,000 barrels per day during the remainder of the term of the agreement. 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.

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 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 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 April 17, 2012, the EPA approved 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. Many nations have agreed to limit emissions of “greenhouse gases” pursuant to the United Nations Framework Convention on Climate Change, also known as the “Kyoto Protocol.” Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are “greenhouse gases,” or GHGs, regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol at this time, several states or geographic regions have adopted legislation and regulations to reduce emissions of GHGs. Additionally, on April 2, 2007, the U.S. Supreme Court ruled, in *Massachusetts, et al. v. EPA* , that the EPA has the authority to regulate the emission of carbon dioxide from automobiles as an “air pollutant” under the federal Clean Air Act. Thereafter, 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, although it does not require immediate reductions in GHG emissions. 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, although it remains subject of several pending lawsuits filed by industry groups. 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. The permitting requirements of the PSD program apply only to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the Tailoring Rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the Tailoring Rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the Tailoring Rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. 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 has also adopted regulations imposing best available control technology requirements on the largest greenhouse gas stationary sources, regulations requiring reporting of greenhouse gas emissions from certain facilities, and it is 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. The U.S. Congress continues to consider legislation to amend the SDWA.

On April 17, 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. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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 is conducting 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, and the Department of the Interior, in a May 4, 2012 proposed rule covering federal lands, 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. On May 31, 2011, the Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process. It was signed into law on June 17, 2011, 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 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 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 “Item 1A. 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.”

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 December 31, 2012, we had approximately 52 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.

ITEM 1A. RISK FACTORS.

The nature of our business activities subjects us to certain hazards and risks. The following is a summary of some of the material risks relating to our business activities. Other risks are described in "Item 1. Business" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk." These risks are not the only risks we face.

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 report were those of Windsor Permian which, prior to our initial public offering, was an entity 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 gas assets of Gulfport located in the Permian Basin in the Gulfport transaction. The oil and natural gas properties described in this report 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 84% 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 84% 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. In 2012, our total capital expenditures, including expenditures for leasehold interests and property acquisitions, drilling, seismic and infrastructure, were approximately $111.8 million. Our 2013 capital budget for drilling, completion and infrastructure, including investments in water disposal infrastructure and gathering line projects, is estimated to be approximately $270.0 million to $300.0 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 initial public offering. However, neither Wexford nor any of its affiliates has made any commitment to provide us additional funding. Notwithstanding prior contributions and loans to us by Wexford or its affiliates, you should not assume that any of them will provide any debt or equity funding to us in the future.

In the near term, we intend to finance our capital expenditures with cash flow from operations 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 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 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 December 31, 2012, we drilled a total of 193 gross wells and participated in an additional 18 gross non-operated wells, of which 191 wells were completed as producing wells and 20 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 December 31, 2012, we had 881 identified potential vertical drilling locations on our existing acreage based on 40-acre spacing and an additional 1,118 identified potential vertical drilling locations based on 20-acre downspacing. We have also identified 731 potential horizontal drilling locations in multiple horizons on our acreage. Only 306 of these 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 and drilling results. 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. We cannot assure you that the analogies we draw from available data from 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.

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 December 31, 2012, the West Texas Intermediate posted price for crude oil was $91.83 per Bbl and the Henry Hub spot market price of natural gas was $3.43 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 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 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. 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. Such contracts 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 $6.0 million at December 31, 2012) and receivables from purchasers of our oil and natural gas production (approximately $8.1 million at December 31, 2012). 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 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.

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 $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 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 years ended December 31, 2012, 2011 and 2010. We may, however, experience ceiling test write downs in the future. See Item 7. “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” 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 report 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 reserves 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.

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 that went into effect for fiscal years ending on or after December 31, 2009 could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules that went into effect for fiscal years ending on or after December 31, 2009 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 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 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 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.

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 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 report 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 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 *"Item 1. Business—Regulation—Environmental Matters and Regulation"* and *"Item 1. Business—Regulation—Other Regulation of the Oil and Natural Gas Industry"* 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. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and 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. The U.S. Congress continues to consider legislation to amend the SDWA.

On April 17, 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. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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 is conducting 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. Also, on May 4, 2012, the U.S. Department of Interior, or DOI, issued a draft rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process, (ii) confirm their wells meet certain construction standards and (iii) establish site plans to manage flowback water. 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 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 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. 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 2013 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 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.

Many nations have agreed to limit emissions of "greenhouse gases" pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are "greenhouse gases," or GHGs, regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol at this time, several states or geographic regions have adopted legislation and regulations to reduce emissions of greenhouse gases. Additionally, on April 2, 2007, the U.S. Supreme Court ruled, in *Massachusetts, et al. v. EPA* , that the EPA has the authority to regulate carbon dioxide emissions from automobiles as "air pollutant" under the federal Clean Air Act. Thereafter, 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, although it does not require immediate reductions in GHG emissions. 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, although it remains subject of several pending lawsuits filed by industry groups. 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. The permitting requirements of the PSD program apply only to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the Tailoring Rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the Tailoring Rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the Tailoring Rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. 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 has also adopted regulations imposing best available control technology requirements on the largest greenhouse gas stationary sources, regulations requiring reporting of greenhouse gas emissions from certain facilities, and it is 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.

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. Further, several individuals who serve as our directors are affiliates 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 DB Energy Holdings LLC, or DB Holdings, imposed in connection with our initial public 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.

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 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.

Our failure to successfully identify, complete and integrate 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 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 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 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 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 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.

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.

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 compensation expense in 2012 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. 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.

In the future, we may incur significant indebtedness in order to make future acquisitions or to develop our properties.

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 current and future outstanding indebtedness will likely 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;
- 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 October 17, 2012 (the last date in 2012 on which we had borrowings outstanding under our revolving credit facility), the weighted average interest rate on such borrowings was 3.72%. 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 $135.0 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 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 our initial public offering, Wexford and Gulfport beneficially owned approximately 44.4% and 21.4%, respectively, of our common stock. 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. 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 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."*

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 will 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. We intend to take advantage of these reporting exemptions until we are no longer an "emerging growth company."

We will remain an "emerging growth company" for up to five years, although if the market value of our common stock that is held by non-affiliates exceeds $700 million as of any June 30 before that time, we would cease to be an "emerging growth company" as of the following December 31.

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.*"

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 an "emerging growth company," as defined in the Jumpstart our Business Startups Act of 2012, and 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 develop or continue for our common stock. If an active public market for our common stock does not develop or 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. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock. All of the shares sold in our initial public offering, except for any shares purchased by our affiliates, are freely tradable. DB Holdings, Gulfport and our directors and executive officers 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 at least 180 days after our initial public offering, which period may be extended under limited circumstances, 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. We have also granted 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;
- 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 credit facilities 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is included in Item 1. "Business" above and in Note 3 of the notes to our combined consolidated financial statements included in this report, which information is incorporated herein by reference.

ITEM 3. LEGAL PROCEEDINGS

Due to the nature of our business, we are, from time to time, involved in 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 the 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.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Price Range of Common Stock

Our common stock is listed on the NASDAQ Global Select Market under the symbol "FANG".

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

2012	High	Low
4th Quarter (1)	$ 19.89	$ 15.65

(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.

Holders of Record

The number of holders of record of our common stock was six on February 22, 2013.

Dividend Policy

We have not paid any cash dividends since our inception. Covenants contained in our senior secured credit facility restrict the payment of cash dividends on our common stock. See Item 1A. "Risk Factors-Risks Related to the Oil and Natural Gas Industry and Our Business-Our revolving credit facility contains restrictive covenants that may limit our ability to respond to changes in market conditions or pursue business opportunities." and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and Capital Resources-Credit Facility." We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Use of Proceeds

On October 11, 2012, our registration statement on Form S-1 (File No. 333-179502) was declared effective and on October 17, 2012, we completed our initial public offering of 14,375,000 shares of common stock, which included 1,875,000 shares of common stock issued pursuant to an 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, after deducting underwriting discounts and commissions and expenses. Of these proceeds, $100.0 million was used to repay the outstanding borrowings under our revolving credit facility, approximately $30.0 million was used to repay the outstanding borrowings under our subordinated note with an affiliate of Wexford, approximately $82 million was used to repay the promissory note issued to Gulfport in the

Gulfport transaction and pay the post closing adjustment to Gulfport and the remaining proceeds were used to fund our exploration and development activities and for general corporate purposes.

Recent Sales of Unregistered Securities

None.

Repurchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

This section presents our selected historical combined consolidated financial data. The selected historical combined consolidated financial data presented below is not intended to replace our historical combined consolidated financial statements. You should read the following data along with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the combined consolidated financial statements and related notes, each of which is included elsewhere in this Annual Report on Form 10-K.

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2012, 2011 and 2010 and the balance sheet data as of December 31, 2012 and 2011 are derived from our audited combined consolidated financial statements included elsewhere in this Annual Report on Form 10-K. The historical financial data for the years ended December 31, 2009 and 2008 and the balance sheet data as of December 31, 2010, 2009 and 2008 are derived from our audited financial statements not included in this Annual Report on Form 10-K.

	Year Ended December 31,				
	2012[1]	2011[2]	2010[2]	2009	2008
Statements of Operations Data:					
Total revenues	$ 74,962,000	$ 49,366,000	$ 27,253,000	$ 12,716,000	$ 18,239,000
Total costs and expenses	57,655,000	34,219,000	18,072,000	11,378,000	103,285,000
Income (loss) from operations	17,307,000	15,147,000	9,181,000	1,338,000	(85,046,000)
Other income (expense)	1,075,000	(15,533,000)	(950,000)	(4,044,000)	(8,903,000)
Income (loss) before income taxes	18,382,000	(386,000)	8,231,000	(2,706,000)	(93,950,000)
Net income (loss)	(36,521,000)	(386,000)	8,231,000	(2,706,000)	(93,950,000)
Pro forma information[3]					
Income before income taxes, as reported	18,382,000				
Pro forma provision for income taxes	6,553,000				
Pro forma net income	11,829,000				
Pro forma earnings per common share[4]					
Basic	$ 0.60				
Diluted	$ 0.60				

	As of December 31,				
	2012(1)	2011(2)	2010(2)	2009	2008
Balance Sheet Data:					
Cash and cash equivalents	$ 26,358,000	$ 6,959,000	$ 4,119,000	$ 2,430,000	$ 8,029,000
Net property and equipment	554,242,000	221,149,000	155,611,000	95,296,000	82,451,000
Total assets	606,701,000	263,578,000	181,315,000	100,073,000	91,869,000
Current liabilities	79,232,000	42,298,000	19,070,000	13,972,000	18,011,000
Long-term debt	193,000	85,000,000	44,767,000	—	—
Stockholders'/ Members' Equity	462,068,000	129,037,000	115,362,000	84,202,000	70,615,000

	Year Ended December 31,				
	2012(1)	2011(2)	2010(2)	2009	2008
Other Financial Data:					
Net cash provided by operating activities	$ 49,692,000	$ 30,998,000	$ 5,192,000	$ 2,702,000	$ 12,042,000
Net cash used in investing activities	(183,078,000)	(81,108,000)	(55,236,000)	(32,150,000)	(84,197,000)
Net cash provided by financing activities	152,785,000	52,950,000	51,733,000	23,849,000	80,183,000

	Year Ended December 31,				
	2012(1)	2011(2)	2010(2)	2009	2008
Adjusted EBITDA(5)	$ 48,223,000	$ 31,864,000	$ 17,398,000	$ 4,617,000	$ 8,966,000

(1) The year ended December 31, 2012 contains the historical results of operations 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 included elsewhere in this Annual Report on Form 10-K.

The year ended December 31, 2012 contains 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 2 to our combined consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

(2) The years ended December 31, 2011 and 2010 contain the historical results of operations 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 included elsewhere in this Annual Report on Form 10-K.

(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 as if the Company and the Predecessors were subject to income taxes since December 31, 2011. 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 included elsewhere in this Annual Report on Form 10-K.

(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 included elsewhere in this Annual Report on Form 10-K.

(5) Adjusted EBITDA is a supplemental non-GAAP financial measure. For a definition of Adjusted EBITDA to net income (loss) see "—Non-GAAP financial measures and reconciliations" below.

Non-GAAP financial measures and reconciliations

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 GAAP financial measure of net income (loss).

	Year Ended December 31,				
	2012	**2011**	**2010**	**2009**	**2008**
Net income (loss):	$ (36,521,000)	$ (386,000)	$ 8,231,000	$ (2,706,000)	$ (93,950,000)
(Gain) loss on derivative instruments	(2,617,000)	13,009,000	148,000	4,068,000	9,528,000
Interest expense	3,610,000	2,528,000	836,000	11,000	—
Depreciation, depletion and amortization	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	2,477,000	544,000	—	—	—
Asset retirement obligation accretion expense	98,000	65,000	38,000	28,000	24,000
Deferred income tax provision	54,903,000	—	—	—	—
Adjusted EBITDA	$ 48,223,000	$ 31,864,000	$ 17,398,000	$ 4,617,000	$ 8,966,000

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our combined consolidated financial statements and notes thereto appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs, and expected performance. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors. See "Item 1A. Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements".

Overview

We are an independent oil and natural gas company focused on the acquisition, development, exploration and exploitation of unconventional, long-life, onshore oil and natural gas reserves in the Permian Basin in West Texas. Our activities are primarily directed at the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations which we refer to as the Wolfberry play. We intend to grow our reserves and production through development drilling, exploitation and exploration activities on our multi-year inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves. Substantially all of our revenues are generated through the sale of oil, natural gas liquids and natural gas production. Our production was approximately 70% oil, 17% natural gas liquids and 13% natural gas for the year ended December 31, 2012, and was approximately 74% oil, 14% natural gas liquids and 12% natural gas for the year ended December 31, 2011. On December 31, 2012, our net acreage position in the Permian Basin was approximately 51,603 net acres.

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. Diamondback Energy LLC was a holding company and did not conduct any material business operations other than its ownership of our common stock and the membership interests in Windsor Permian LLC, or Windsor Permian. As a result of the merger, Windsor Permian became a wholly-owned subsidiary of Diamondback. Also on October 11, 2012, Wexford, 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." 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. We refer to the historical results of Windsor Permian and Windsor UT prior to October 11, 2012 as our "Predecessors."

Also on October 11, 2012, we acquired all of the oil and natural gas properties of Gulfport located in the Permian Basin in exchange for (i) 7,914,036 shares of our common stock, (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 and (iii) a post-closing cash adjustment of approximately $18.6 million. We are the operator of the acreage acquired by us from Gulfport.

On October 17, 2012, we completed our initial public offering of 12,500,000 shares of our common stock at a price to the public of $17.50 per share. On October 23, 2012, the underwriters purchased an additional 1,875,000 shares of our common stock following the exercise in full of their over-allotment option. We received net proceeds of approximately $234.1 million from the sale of these shares of common stock, net of estimated offering expenses and underwriting discounts and commissions.

Basis of Presentation

Transfers of a business between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information. As discussed above, the Windsor UT contribution was accounted for as a transaction between entities under common control. Accordingly, the financial information and production and reserve data contained herein have been retrospectively adjusted to include the historical results of Windsor UT at historical carrying values and its operations as if it was combined for all periods presented.

In June 2012, Windsor Permian distributed to its sole member its minority equity interests in Bison Drilling and Field Services LLC, or Bison, and a 33% interest in Muskie Holdings LLC, or Muskie, so we could focus our activities on our oil and natural gas exploration and development activities. Bison was formed in November 2010 as a wholly-owned subsidiary of Windsor Permian. Beginning on March 31, 2011, various related party investors contributed capital to Bison diluting our ownership interest to approximately 22%. We assessed our ability to exercise financial control over Bison and based on the results of the assessment, we concluded that we maintained significant influence but we no longer had the ability to exercise control over Bison. We deconsolidated Bison for financial reporting purposes as of March 31, 2011 and the previously consolidated amounts were removed from the combined consolidated balance sheet and reflected as an equity method investment. We eliminated intercompany profits or losses in relation to our continuing involvement with Bison, proportionate to our equity interest. Under the equity method, generally our share of investees' earnings or loss is recognized in the combined consolidated statements of operations. However, because substantially all of Bison's earnings were generated by performing services on properties owned and operated by us, our share of Bison's earnings have been credited to oil and gas properties. We recorded revenues of $1.5 million attributable to Bison in our combined consolidated statements of operations during the first quarter of 2011. Muskie was formed in 2011, and owns certain assets, real estate and rights in a lease for land that is prospective for oil and natural gas fracture grade sand. We recorded a loss from equity method investments of $7,000 for 2011. The interests in Bison and Muskie are reflected in "Investments-equity method" on our combined consolidated balance sheets. For additional information regarding Bison and Muskie, see Note 5—Equity Method Investments to our combined consolidated financial statements appearing elsewhere in this report.

Since we began operations in 2007, we have increased our drilling activity, evaluated potential acquisitions and added to our acreage portfolio. Because of our growth through acquisitions and development of our properties, our historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results.

Operating Results Overview

During the year ended December 31, 2012, our average daily production was approximately 2,946 BOE, consisting of 2,066 Bbls/d of oil, 2,277 Mcf/d of natural gas and 500 Bbls/d of natural gas liquids, an increase of 78%, or 1,288 BOE/d, from average daily production of 1,658 BOE/d for the year ended December 31, 2011, consisting of 1,231 Bbls/d of oil, 1,133 Mcf/d of natural gas and 238 Bbls/d of natural gas liquids.

During the year ended December 31, 2012, we drilled 57 gross (41 net) wells, and participated in an additional eight gross (three net) non-operated wells, in the Permian Basin.

Reserves and pricing

In the table below, Ryder Scott estimated all of our proved reserves at December 31, 2012 and 2011. Pinnacle estimated all of our proved reserves at December 31, 2010. The prices used to estimate proved reserves for all periods did not give effect to derivative transactions, were held constant throughout the life of the properties and have been adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

	2012	2011	2010
Estimated Net Proved Reserves:			
Oil (Bbls)	26,196,859	18,100,473	19,630,160
Natural gas (Mcf)	34,570,148	20,551,465	22,695,080
Natural gas liquids (Bbls)	8,251,429	5,049,560	5,832,967
Total (BOE)	40,209,979	26,575,277	29,245,640

	2012	2011	2010
		Unweighted Arithmetic Average First-Day-of-the-Month Prices	
Oil (Bbls)	$ 88.13	$ 93.09	$ 77.61
Natural gas (Mcf)	$ 2.86	$ 3.91	$ 4.14
Natural gas liquids (Bbls)	$ 43.88	$ 56.33	$ 40.74

Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. For the years ended December 31, 2012 and 2011, our revenues were derived 88% and 84%, respectively, from oil sales, 9% and 10%, respectively, from natural gas liquids sales, 3% and 3%, respectively, from natural gas sales and none and 3%, respectively, from oil and natural gas services. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Oil, natural gas liquids and natural gas prices have historically been volatile. During 2012, West Texas Intermediate posted 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 December 31, 2012, the West Texas Intermediate posted price for crude oil was $91.83 per Bbl and the Henry Hub spot market price of natural gas was $3.43 per MMBtu.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time-to-time we enter into derivative arrangements for our crude oil and natural gas production. We utilize commodity derivatives to reduce our exposure to fluctuations in NYMEX WTI and Brent Crude benchmark prices. While these derivative contracts stabilize our cash flows when market prices are below our contract prices, they also prevent us from realizing increases in our cash flow when market prices are higher than our contract prices. We will sustain realized and unrealized losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will sustain realized and unrealized gains to the extent our derivatives contract prices are higher than market prices. Our derivatives contracts are not designated as accounting hedges and, as a result, gains or losses on derivatives contracts are recorded as other income (expense) in our statements of operations. For the year-end status of our derivatives, see Note 11—Derivatives, and for derivative contracts entered into subsequent to December 31, 2012, see Note 14—Subsequent Events in the Notes to the Combined Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Principal components of our cost structure

Lease operating and natural gas transportation and treating expenses. These are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workover expenses related to our oil and natural gas properties.

Production taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and gas properties.

General and administrative. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other fees for professional services and legal compliance.

Depreciation, depletion and amortization. Under the full cost accounting method, we capitalize costs within a cost center and then systematically expense those costs on a units of production basis based on proved oil and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing proved reserves; and (iii) the estimated dismantlement and abandonment costs, net of estimated salvage values. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years.

Impairment expense. This is the cost to reduce proved oil and gas properties to the calculated full cost ceiling value.

Other income (expense)

Interest income. This represents the interest received on our cash and cash equivalents.

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our credit facility. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense.

Gain/Loss on derivative instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of crude oil. This amount represents (i) the recognition of unrealized gains and losses associated with our open derivative contracts as commodity prices change and commodity derivative contracts expire or new ones are entered into, and (ii) our realized gains and losses on the settlement of these commodity derivative instruments.

Loss from equity investment. This line item represents our proportionate share of the earnings and losses from our investment in the membership interests of Muskie, an equity method investment.

Income tax expense. Prior our initial public offering in October 2012, the operations of Windsor Permian and Windsor UT, as limited liability companies, were not subject to federal income taxes. At the date of the merger of Diamondback Energy LLC with and into Diamondback, 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 use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

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Results of Operations

The following table sets forth selected historical operating data for the periods indicated.

	Year Ended December 31, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010
Operating Results:			
Revenues			
Oil and natural gas revenues	$ 74,962,000	$ 47,875,000	$ 26,442,000
Other revenue	—	1,491,000	811,000
Operating Expenses			
Lease operating expense	16,793,000	10,597,000	4,589,000
Production taxes	3,691,000	2,366,000	1,347,000
Gathering and transportation expense	424,000	202,000	106,000
Oil and natural gas services	—	1,733,000	811,000
Depreciation, depletion and amortization	26,273,000	15,601,000	8,145,000
General and administrative	10,376,000	3,655,000	3,036,000
Asset retirement obligation accretion expense	98,000	65,000	38,000
Total expenses	57,655,000	34,219,000	18,072,000
Income from operations	17,307,000	15,147,000	9,181,000
Net interest expense	(3,607,000)	(2,517,000)	(802,000)
Other income - related party	2,132,000	—	—
Gain (loss) on derivative instruments	2,617,000	(13,009,000)	(148,000)
Loss from equity investment	(67,000)	(7,000)	—
Total other income (expense)	1,075,000	(15,533,000)	(950,000)
Income (loss) before income taxes	18,382,000	(386,000)	8,231,000
Provision for income taxes	54,903,000	—	—
Net income (loss)	$ (36,521,000)	$ (386,000)	$ 8,231,000
Production Data:			
Oil (Bbls)	756,286	449,434	280,721
Natural gas (Mcf)	833,516	413,640	323,847
Natural gas liquids (Bbls)	183,114	86,815	79,978
Combined volumes (Boe)	1,078,320	605,189	414,674
Daily combined volumes (Boe/d)	2,946	1,658	1,136
Average Prices[1]:			
Oil (per Bbl)	$ 86.88	$ 92.24	$ 76.51
Natural gas (per Mcf)	2.85	3.98	4.32
Natural gas liquids (per Bbl)	37.57	54.98	44.56
Combined (per BOE)	69.52	79.11	63.77
Average Costs (per BOE)			
Lease operating expense	$ 15.57	$ 17.51	$ 11.07
Gathering and transportation expense	0.39	0.33	0.26
Production taxes	3.42	3.91	3.25
Production taxes as a % of sales	4.9%	4.9%	5.1%
Depreciation, depletion, and amortization	24.36	25.78	19.64
General and administrative	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 $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 our hedging arrangements during 2010.

Comparison of the Years Ended December 31, 2012 and December 31, 2011

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $27,087,000, or 57%, to $74,962,000 for the year ended December 31, 2012 from $47,875,000 for the year ended December 31, 2011. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 1,288 BOE/d during the year ended December 31, 2012 as compared to the year ended December 31, 2011. The total increase in revenue of approximately $27,087,000 is largely attributable to higher oil, natural gas liquids and natural gas production volumes for the year ended December 31, 2012 as compared to the year ended December 31, 2011. The increases in production volumes were due to a combination of increased drilling activity and the effect of the contribution of Gulfport's Permian Basin assets during the period October 11, 2012 through December 31, 2012. The revenue increase attributable to the contribution of assets from Gulfport during the period October 11, 2012 through December 31, 2012 was $7,353,000. Our production increased by 306,852 Bbls of oil, 96,299 Bbls of natural gas liquids and 419,876 Mcf of natural gas for the year ended December 31, 2012 as compared to the year ended December 31, 2011. The net dollar effect of the decreases in prices of approximately $8,183,000 (calculated as the change in period-to-period average prices times current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $35,270,000 (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas times the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ (5.36)	756,286	$ (4,055)
Natural gas liquids	$ (17.41)	183,114	$ (3,188)
Natural gas	$ (1.13)	833,516	$ (940)
Total revenues due to change in price			$ (8,183)
	Change in production volumes(1)	**Prior period Average Prices**	**Total net dollar effect of change (in thousands)**
Effect of changes in production volumes:			
Oil	306,852	$ 92.24	$ 28,304
Natural gas liquids	96,299	$ 54.98	$ 5,294
Natural gas	419,876	$ 3.98	$ 1,672
Total revenues due to change in production volumes			$ 35,270
Total change in revenues			$ 27,087

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas

Lease Operating Expense. Lease operating expense was $16,793,000 ($15.57 per BOE) for the year ended December 31, 2012, an increase of $6,196,000, or 58%, from $10,597,000 ($17.51 per BOE) for the year ended December 31, 2011. The increase is due to increased drilling activity, which resulted in additional producing wells for the year ended December 31, 2012 as compared to the year ended December 31, 2011. Our lease operating expense during both periods was also adversely impacted by the cost of processing and treating non-hydrocarbon gases from certain of our wells that came on-line in 2011. During the fourth quarter of 2012, we completed construction of both oil and water gathering systems that will transport this gas stream to a sour gas pipeline, thereby eliminating the monthly processing and treating expense, and reducing water trucking, respectively. In addition, in the first quarter 2013, we moved a portion of our produced water to pipe connected to a commercial salt water disposal well. We believe that the completion of the gathering systems, the connection to a salt water disposal well and other actions will help reduce our lease operating expense in future periods.

Production Tax Expense. Production taxes as a percentage of oil and natural gas sales was 4.9% for both the year ended December 31, 2012 and 2011. Production taxes are primarily based on the market value of our production at the wellhead and may vary across the different counties in which we operate. Total production taxes increased $1,325,000, from $2,366,000 during the year ended December 31, 2011 to $3,691,000 during the year ended December 31, 2012, as a result of higher production and an increase in the market value of our production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $10,672,000, or 68%, from $15,601,000 for the year ended December 31, 2011 to $26,273,000 for the year ended December 31, 2012. This increase was due to an increase in our full cost pool as a result of our acquisitions and capital spending. The average depletion rate was $24.36 for the year ended December 31, 2012 and $25.78 for the year ended December 31, 2011. The average depletion rate includes oil and gas depletion and other property and equipment depreciation. The decrease in depletion rate was due to an increase in proved reserves at December 31, 2012.

General and Administrative Expense. General and administrative expense increased $6,721,000 from $3,655,000 for the year ended December 31, 2011 to $10,376,000 for the year ended December 31, 2012. The increase was due to increases in salary, legal, professional service and contract labor expenses. These increases were partially offset by increases in general and administrative costs related to exploration and development activity capitalized to the full cost pool and increases in COPAS overhead reimbursements due to increased drilling activity. In connection with our initial public offering, we incurred a non-recurring charge to our fourth quarter general and administrative expense of approximately $2.7 million for executive bonuses and non-cash equity based compensation expense associated with such offering.

Net Interest Expense. Net interest expense for the year ended December 31, 2012 was $3,607,000, as compared to $2,517,000 for the year ended December 31, 2011, an increase of $1,090,000. This increase is due primarily to an increase in our weighted average outstanding borrowings under our credit agreement to $77,489,000 for the year ended December 31, 2012 from $68,409,000 for the same period in 2011.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value on derivative instruments in our combined consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments.” For the years ended December 31, 2012 and 2011, we had a realized loss on settlement of derivative instruments of $5,440,000 and $37,000, respectively. For the years ended December 31, 2012 and 2011, we had an unrealized gain on open derivative instruments of $8,057,000 and an unrealized loss of $12,972,000, respectively.

Income tax expense. Prior to our initial public offering in October 2012, the operations of Windsor Permian and Windsor UT as limited liability companies, were not subject to federal income taxes. As of October 11, 2012, the date of the merger of Diamondback Energy LLC with and into Diamondback, 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. For the year ended December 31, 2012 we recorded a deferred income tax expense of $54,903,000. Income tax expense of $761,000 was incurred as a result of operations from October 11, 2012 through December 31, 2012.

Year ended December 31, 2011 Compared to Year ended December 31, 2010

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $21,433,000, or 81%, to $47,875,000 for the year ended December 31, 2011 from $26,442,000 for the year ended December 31, 2010. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 522 BOE/d during the year ended December 31, 2011 as compared to the year ended December 31, 2010. The total increase in revenue of approximately $21,433,000 is largely attributable to higher oil, natural gas liquids and natural gas production volumes and an increase in the prices of oil and natural gas liquids realized for the year ended December 31, 2011 as compared to the year ended December 31, 2010. Production increased by 168,713 Bbls of oil, 6,837 Bbls of natural gas liquids and 89,793 Mcf of natural gas for the year ended 2011 as compared to the year ended 2010. The net dollar effect of the increase in prices of approximately $7,832,000 (calculated as the change in year-to-year average prices times current year production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $13,601,000 (calculated as the increase in year-to-year volumes for oil, natural gas liquids and natural gas times the prior year average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 15.73	449,434	$ 7,069
Natural gas liquids	$ 10.42	86,815	$ 904
Natural gas	$ (0.34)	413,640	$ (141)
Total revenues due to change in price			$ 7,832
	Change in production volumes(1)	**Prior period Average Prices**	**Total net dollar effect of change (in thousands)**
Effect of changes in production volumes:			
Oil	168,713	$ 76.51	$ 12,908
Natural gas liquids	6,837	$ 44.56	$ 305
Natural gas	89,793	$ 4.32	$ 388
Total revenues due to change in production volumes			$ 13,601
Total change in revenues			$ 21,433

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas

Lease Operating Expense. Lease operating expense was $10,597,000 ($17.51 per BOE) for the year ended December 31, 2011, an increase of $6,008,000, or 131%, from $4,589,000 ($11.07 per BOE) for the year ended December 31, 2010. The increase is due to increased drilling activity, which resulted in additional producing wells for the year ended December 31, 2011 as compared to the year ended December 31, 2010. On a per-BOE basis, the increase is due to cost increases in services and supplies (primarily as a result of higher demand for such services and supplies in the Permian Basin and higher commodity prices), the cost of repairing and replacing downhole equipment due to rod and tubing configurations and pumping practices that resulted in a higher rate of well failures during 2011 and the associated downtime and loss of production as these failures were remediated. Our lease operating expense for the year ended December 31, 2011 was also adversely impacted by the cost of processing and treating non-hydrocarbon gases from certain of our wells that came on line in 2011.

Production Tax Expense. Production taxes as a percentage of oil and natural gas sales were 4.9% for the year ended December 31, 2011 as compared to 5.1% for the year ended December 31, 2010. Production taxes are primarily based on the market value of our production at the wellhead and vary across the different counties in which we operate. Total production taxes increased $1,019,000, or 76%, from $1,347,000 during the year ended

December 31, 2010 to $2,366,000 during the year ended December 31, 2011 as a result of higher production and an increase in the market value of our production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $7,456,000, or 92%, from $8,145,000 for the year ended December 31, 2010 to $15,601,000 for the year ended December 31, 2011. The average depletion rate was $25.78 per BOE for the year ended December 31, 2011 and $19.64 per BOE for the year ended December 31, 2010. The average depletion rate includes oil and gas depletion and other property and equipment depreciation. The depletion rate increase was due primarily to an increase in costs and a decrease in proved reserves at December 31, 2011.

General and Administrative Expense. General and administrative expense increased $619,000 from $3,036,000 for the year ended December 31, 2010 to $3,655,000 for the year ended December 31, 2011. A $2,012,000 increase primarily attributable to salary and equity based compensation expense for our new executive team was partially offset by the capitalization of $871,000 of such expense and a $522,000 increase in COPAS overhead reimbursements due to increased drilling activity.

Net Interest Expense. Net interest expense for the year ended December 31, 2011 was $2,517,000, as compared to $802,000 for the year ended December 31, 2010, an increase of $1,715,000. Our weighted average outstanding principal under our credit agreement was $68,520,000 for the year ended December 31, 2011 as compared to $21,245,000 for 2010 due to our increased drilling activity.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value on derivative instruments in the combined consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments.” For the years ended December 31, 2011 and 2010, we had a realized loss on settlement of derivative instruments of $37,000 and $148,000, respectively. For the years ended December 31, 2011 and 2010, we had an unrealized loss on open derivative instruments of $12,972,000 and zero, respectively.

Liquidity and Capital Resources

Our primary sources of liquidity have been capital contributions and loans from our equity sponsor, borrowings under our credit facility, proceeds from our IPO and cash flows from operations. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. As we pursue reserves and production growth, we regularly consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us.

Liquidity and cash flow

Our cash flows for the years ended December 31, 2012, 2011 and 2010 are presented below:

	Year Ended December 31,		
	2012	2011	2010
Net cash provided by operating activities	$ 49,692,000	$ 30,998,000	$ 5,192,000
Net cash used in investing activities	(183,078,000)	(81,108,000)	(55,236,000)
Net cash provided by financing activities	$ 152,785,000	$ 52,950,000	$ 51,733,000
Net change in cash	$ 19,399,000	$ 2,840,000	$ 1,689,000

Operating Activities

Net cash provided by operating activities was $49,692,000 for the year ended December 31, 2012 as compared to $30,998,000 for the year ended December 31, 2011. The increase in operating cash flows is largely a result of our increased drilling activities throughout 2012.

Net cash provided by operating activities was $30,998,000 for the year ended December 31, 2011 as compared to $5,192,000 for the year ended December 31, 2010. The increase in operating cash flows is due to an overall increase in production revenues, partially offset by increased expenses, as discussed above in "—Results of operations".

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas we produce. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

Investing Activities

The purchase and development of oil and natural gas properties accounted for the majority of our cash outlays for investing activities. We used cash for investing activities of $183,078,000, $81,108,000 and $55,236,000 during the years ended December 31, 2012, 2011 and 2010, respectively.

During the year ended December 31, 2012, we spent $100,090,000 on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 65 gross (44 net) wells. We spent an additional $11,707,000 on leasehold costs, $1,102,000 for the purchase of other property and equipment and $6,637,000, net, on the settlement of derivative transactions. On October 11, 2012, we acquired all of the oil and natural gas properties of Gulfport located in the Permian Basin in exchange for (i) 7,914,036 shares of our common stock, (ii) $63,590,000 in the form of a non-interest bearing promissory note that was repaid in full upon the closing of our initial public offering and (iii) a post-closing cash adjustment of approximately $18,550,000.

During 2011, we spent $76,470,000 on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 56 gross (32 net) wells. We spent an additional $3,704,000 on leasehold costs, $7,065,000 for the purchase of other property and equipment, $4,137,000 for the purchase of certain assets, real estate and leasehold interests which were subsequently contributed to Muskie and $2,460,000 for the purchase of drilling rigs and other equipment which were subsequently contributed to Bison. These amounts were partially offset by proceeds of $6,000,000 from a partial sale of our equity investment, $55,000 from the sale of property and equipment and $76,000 from the settlement of non-hedge derivative investments and margin deposits.

During 2010, we spent $39,230,000 on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 43 gross (27 net) wells. We spent an additional $5,344,000 for the purchase and development of leasehold interests, $11,741,000 million for the purchase of drilling rigs, well servicing equipment and other equipment which were subsequently contributed to Bison and $191,000 for the settlement of non-hedge derivative instruments and margin deposits. These amounts were partially offset by the $1,250,000 we received from the sale of approximately 10,946 net acres of non producing acreage in the Permian Basin.

Our investing activities for the years ended December 31, 2012, 2011 and 2010 are summarized in the following table:

	Year Ended December 31,		
	2012	2011	2010
Drilling and completion of wells	$ (100,090,000)	$ (76,470,000)	$ (39,230,000)
Purchase of leasehold acquisitions	(11,707,000)	(3,704,000)	(5,344,000)
Acquisition of Gulfport properties	(63,590,000)	—	—
Purchase of other property and equipment	(1,102,000)	(7,065,000)	(11,741,000)
Proceeds from sale of property and equipment	48,000	55,000	1,270,000
Settlement of non-hedge derivative instruments	(8,963,000)	(4,127,000)	(3,963,000)
Receipt on derivative margins	2,326,000	4,203,000	3,772,000
Proceeds from equity investment, net	—	6,000,000	—
Net cash used in investing activities	$ (183,078,000)	$ (81,108,000)	$ (55,236,000)

Financing Activities

Net cash provided by financing activities for the year ended December 31, 2012 was $152,785,000 as compared to $52,950,000 for 2011. On October 17, 2012, our IPO was completed and we received net proceeds of approximately $234.1 million, after deducting the underwriting discount. During 2012 and 2011, we borrowed $15,000,000 and $40,233,000, respectively, under our revolving credit facility. All borrowings outstanding under our revolving credit facility were repaid with proceeds of the IPO. During 2012, we borrowed $30,000,000 under our subordinated note with Wexford. This note was repaid with proceeds of the IPO and was canceled. During 2012 and 2011, we received capital contributions from our members of $4,008,000 and $13,517,000, respectively. These proceeds were used primarily to fund our drilling costs and purchase property and equipment. During the year ended December 31, 2012, we paid $2,887,000 for costs associated with our initial public offering.

Net cash provided by financing activities for 2011 was $52,950,000 as compared to $51,733,000 for 2010. During 2011, we borrowed $40,233,000 under our revolving credit facility and received capital contributions from our members of $13,517,000. These proceeds were used primarily to fund our drilling costs and purchase property and equipment.

Net cash provided by financing activities for 2010 was $51,733,000. The net cash provided by financing activities in 2010 is primarily attributable to borrowings of $61,066,000 under our revolving credit facility, partially offset by principal payments of $23,950,000 under our prior credit facility with the Bank of Oklahoma, N.A. During 2010, we received capital contributions from our members of $28,508,000, which included a non-cash contribution of property of $7,594,000, and were partially offset by distributions to our members of $5,579,000. We paid $718,000 in debt issuance costs in 2010. We used the net proceeds from our financing activities during 2010 to fund our drilling costs, the purchase of property and equipment, the purchase of tubular goods inventory and the acquisition and development of leasehold interests.

Credit Facility

On October 15, 2010, we entered into a secured loan agreement with BNP Paribas, or BNP, as the administrative agent, sole book runner and lead arranger. On May 10, 2012, the revolving credit agreement was amended to provide for the resignation of BNP, and the appointment of Wells Fargo Bank, National Association, as administrative agent for the lenders. The loan agreement, as amended, provides for a $250 million revolving credit facility, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves (the “borrowing base”). The outstanding borrowings 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.

Principal may be optionally repaid from time to time and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise and (b) at the maturity date of October 15, 2014. We are obligated to pay a quarterly commitment fee equal to 0.5% per year of the unused portion of the borrowing base. The loan is secured by substantially all of our assets. The borrowing base is re-determined semi-annually with effective dates of April 1st and October 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. The borrowing base was $45.0 million at December 31, 2010. The borrowing base was increased several times during 2011 as a result of redeterminations and at December 31, 2011 the borrowing base was $100.0 million. The borrowing base increased in 2012 through redeterminations and at December 31, 2012 the borrowing base was $135.0 million. In connection with the IPO, we repaid all outstanding borrowings under our revolving credit facility and as of December 31, 2012 had no outstanding borrowings.

Our revolving credit agreement contains various affirmative and restrictive covenants. These covenants, among other things, prohibit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of various financial ratios described below.

As of July 24, 2012, our revolving credit agreement was amended and restated to include Diamondback Energy LLC and its subsidiaries as additional guarantors to the facility. The covenant prohibiting additional indebtedness was also amended to allow the issuance of unsecured debt of up to $250.0 million and, in connection with any such issuance, the reduction of the borrowing base by 25% of the principal amount of such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. The amendment also provided that redemptions of any unsecured debt will be restricted unless certain liquidity requirements are met. Further, the amendment modified certain financial ratios, the current requirements of which are described below.

Financial Covenant	Required Ratio
Ratio of EBITDAX to interest expense, as defined in the credit agreement	Not less than 2.5 to 1.0
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of debt under revolving credit agreement to EBITDAX	Not greater than 3.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

Our revolving credit agreement defines EBITDAX, for any period, as the sum of our consolidated net income for such period plus the following expenses or charges to the extent deducted from our consolidated net income for such period: interest; income taxes; depreciation, depletion, amortization and exploration expenses; extraordinary items and other similar non-cash charges, including expenses related to stock-based compensation and hedging, minus all non-cash income added to our consolidated net income.

As of July 31, 2012, the first amendment to our amended and restated credit agreement was executed, which provided for the issuance to Gulfport of the Gulfport transaction note and the payment of the Gulfport transaction note from the proceeds of our initial public offering.

As of September 28, 2012, the second amendment to our amended and restated credit agreement was executed, which among other things provided for an increase in permitted subordinated debt in a maximum principal amount not to exceed $45.0 million, including any such indebtedness evidenced by our subordinated note with an affiliate of Wexford described in more detail under “-Subordinated Note” below, waived compliance with our current ratio covenant for the quarter ending September 30, 2012 and increased the aggregate limitation on lease payments during any period of twelve consecutive months from $250,000 to $550,000.

As of December 31, 2012, we were in compliance with all financial covenants under our revolving credit facility. The lenders may accelerate all of the indebtedness under our revolving credit facility upon the occurrence of any event of default unless we cure any such default within any applicable grace period. For payments of principal and interest under our revolving credit facility, we generally have a three business day grace period, and a 30-day cure period for most covenant defaults, but not for defaults of certain specific covenants, including the financial covenants and negative covenants.

Prior Revolving Credit Facility

On September 17, 2009, we entered into a revolving credit facility with the Bank of Oklahoma, N.A., or BOK. The BOK revolving credit facility had a maximum principal amount of $50.0 million, subject to a collateral borrowing base calculation which was based on the underlying reserve value of the oil and natural gas properties securing the credit facility and outstanding letters of credit. The BOK revolving credit facility was repaid in full in October 2010 with borrowings under the BNP revolving credit facility and then terminated.

Borrowings under the BOK revolving credit facility bore interest at our election of either BOK’s listed national prime rate plus an interest rate spread ranging from 1.0% to 2.5% (based on borrowing levels) payable monthly or at LIBOR rates plus an interest rate spread ranging from 2.5% to 4.0% (based on borrowing levels) payable at the end of the applicable interest period. The credit facility agreement allowed BOK to charge a 0.25% commitment fee on the unused available borrowing.

The BOK revolving credit facility was collateralized by oil and natural gas properties and contained certain financial and non-financial covenants, which included: providing quarterly financial statements and annual audited financial statements; providing semi-annual reserve engineering reports; restrictions on distributions to members; restrictions on incurring additional debt; restrictions on financial derivative contracts; maintaining a funded debt to earnings before hedge gains or losses, asset gains or losses, depreciation, depletion, amortization and interest expense of no greater than 3.0 to 1.0.

Subordinated Note

Effective May 14, 2012, we executed an unsecured subordinated note with an affiliate of Wexford pursuant to which, as amended, the Wexford affiliate could, from time to time, advance up to an aggregate $45.0 million. These advances were solely at Wexford's discretion and neither Wexford nor any of its affiliates had any commitment or obligation to provide further 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 the note. The unpaid principal balance and all accrued interest on the note was 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. We repaid the outstanding borrowings under this note in full, with a portion of the net proceeds from our initial public offering and the note was canceled.

Capital Requirements and Sources of Liquidity

We currently anticipate our 2013 capital budget for drilling and infrastructure will be approximately $270.0 million to $300.0 million for 2013. 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 as follows:

- $190.0 million for the drilling and completion of horizontal operated wells;
- $66.0 million for the drilling and completion of vertical operated wells;
- $12.0 million for our participation in the drilling and completion of non-operated wells; and
- $17.0 million for the construction of infrastructure to support production, including investments in water disposal infrastructure and gathering line projects.

However, the amount and timing of these capital expenditures is 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.

Based upon current oil and natural gas price expectations for 2013, we believe that our cash flow from operations and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2013. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. Further, our 2013 capital expenditure budget does not allocate any funds for leasehold interest and property acquisitions. We monitor and adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, contractual obligations, internally generated cash flow and other factors both within and outside our control. If we require additional capital, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financing, asset sales, offerings of debt and or equity securities or other means. We cannot assure you that the needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our drilling programs, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to replace our reserves.

Contractual Obligations and Other Commitments

The following table summarizes our contractual obligations and commitments as of December 31, 2012:

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long term debt[1]	$ 338,000	$ 145,000	$ 193,000	$ —	$ —
Interest and commitment fees[2]	1,181,000	675,000	506,000	—	—
Derivative contracts	5,205,000	4,817,000	388,000	—	—
Asset retirement obligations [3]	2,145,000	20,000	—	—	2,125,000
Fracturing and Well Stimulation Service Agreements	18,000,000	14,400,000	3,600,000	—	—
Operating lease obligations	2,195,000	485,000	992,000	693,000	25,000
	$ 29,064,000	$ 20,542,000	$ 5,679,000	$ 693,000	$ 2,150,000

(1) Long term debt consists of the outstanding principal amount under our revolving credit facility and an installment payment contract for the purchase of computer equipment. We have no outstanding borrowings under our revolving credit facility at December 31, 2012. Any subsequent borrowings under our revolving credit facility are due on October 15, 2014.

(2) This table reflects only the minimum amount of interest and commitment fees due, which as of December 31, 2012 includes a commitment fee equal to 0.5% per year of the unused portion of the borrowing base of our revolving credit facility. The table does not include interest expense or other fees payable under this floating rate facility as we cannot predict the timing of future borrowings and repayments or interest rates to be charged.

(3) Amounts represent our estimates of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 4 of the notes to our combined consolidated financial statements set forth in Part IV, Item 15 of this Form 10-K.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon our combined consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. See Note 1 of the Notes to the Combined Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Use of Estimates

Certain amounts included in or affecting our combined consolidated financial statements and related disclosures must be estimated by our management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the combined consolidated financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities and our disclosure of contingent assets and liabilities at the date of the combined consolidated financial statements. Actual results could differ from those estimates.

We evaluate these estimates on an ongoing basis, using historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, asset retirement obligations, the fair value determination of acquired assets and liabilities, stock-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

Method of accounting for oil and natural gas properties

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. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal 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.

Costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We assess all items classified as unevaluated property on an annual basis for possible impairment. We assess properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Oil and natural gas reserve quantities and standardized measure of future net revenue

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. The SEC has defined proved reserves as the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil and gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Revenue recognition

Oil and natural gas revenues are recorded when title passes to the purchaser, net of royalty interests, discounts and allowances, as applicable. We account for oil and natural gas production imbalances using the sales method, whereby a liability is recorded when our volumes exceed our estimated remaining recoverable reserves. No receivables are recorded for those wells where we have taken less than our ownership share of production. We did not have any gas imbalances as of December 31, 2012, 2011 and 2010. Revenues from oil and natural gas services are recognized as services are provided.

Impairment

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, impairment and deferred income taxes exceed the discounted future net revenues of proved oil and natural gas reserves, less any related income tax effects, the excess capitalized costs are charged to expense. In calculating future net revenues, prices are calculated as the average oil and gas prices during the preceding 12-month period prior to the end of the current reporting period, determined as the unweighted arithmetic average first-day-of-the-month prices for the prior 12-month period and costs used are those as of the end of the appropriate quarterly period.

Asset retirement obligations

We measure the future cost to retire our tangible long-lived assets and recognize such cost as a liability in accordance with ASC Topic 410, *Asset Retirement and Environmental Obligations* ("ASC Topic 410"), which provides accounting and reporting guidance for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction or normal operation of a long-lived asset. ASC Topic 410 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred if a reasonable estimate of fair value can be made and that the corresponding cost be capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, the difference is recorded in oil and natural gas properties.

Our asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. We estimate the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and gas property balance.

Derivatives

From time to time, we have used energy derivatives for the purpose of mitigating the risk resulting from fluctuations in the market price of crude oil. We recognize all of our derivative instruments as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and further on the type of hedging relationship. We enter into counter-swaps from time to time for the purpose of locking-in the value of a swap. 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. For those derivative instruments that are designated and qualify as hedging instruments, we designate the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge. Changes in the fair value of instruments designated as a fair value hedge offset changes in the fair value of the hedge item and changes in the fair value of instruments designated as cash flow hedges are shown in accumulated other comprehensive income until the hedged item is recognized in earnings. For derivative instruments not designated as hedging instruments, the unrealized gain or loss on the change in fair value of these instruments are recognized in earnings during the period of change. None of our derivatives were designated as hedging instruments during the years ended December 31, 2012, 2011 and 2010.

Accounting for Stock-Based Compensation

We account for stock-based compensation in accordance with the provisions of ASC Topic 718, "Compensation—Stock Compensation". We grant various types of stock-based awards including stock options and restricted stock units. These plans and related accounting policies are defined and described more fully in Note 8—Stock and Equity Based Compensation. Stock compensation awards are measured at fair value on the date of grant and are expensed, net of estimated forfeitures, over the required service period.

Income Taxes

We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

Recent accounting pronouncements

In December 2011, the FASB issued Accounting Standards Update No. 2011-11, *Disclosures about Offsetting Assets and Liabilities*. In January 2013, the FASB issued Accounting Standards Update No. 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*. The guidance in ASU No. 2013-01 limits the scope of the new balance sheet offsetting disclosures to derivatives, repurchase agreements, and securities lending transactions to the extent that they are (1) offset in the financial statements or (2) subject to an enforceable master netting arrangement or similar agreement. The disclosures are required to enable users of financial statements to understand significant quantitative differences in balance sheets prepared in accordance with accounting principles generally accepted in the U.S. ("GAAP") and International Financial Reporting Standards related to the offsetting of financial instruments. The existing GAAP guidance allowing balance sheet offsetting, including industry-specific guidance, remains unchanged. The guidance in ASU No. 2011-11and ASU No. 2013-01 is effective for annual and interim reporting periods beginning on or after January 1, 2013. The disclosures should be applied retrospectively for all prior periods presented. We do not expect the adoption of this guidance to have a significant impact on our financial position, results of operations or cash flow.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on results of operations for the years ended 2012, 2011 and 2010. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations.

Off-balance sheet arrangements

We currently have no off-balance sheet arrangements. Please read Note 13 included in Notes to the Combined Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K, for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control.

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. 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 the remaining swaps settling 324,000 Bbls of crude oil swaps. In October 2011, we placed a swap contract covering 730,000 Bbls of crude oil for the period from January 2012 to December 2013 at a fixed price of $78.50 for 2012 and $80.55 for 2013. Such contracts 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.

At December 31, 2012, we had a net liability derivative position of $5,205,000 related to our price swap derivatives, as compared to a net liability derivative position of $14,459,000 as of December 31, 2011 related to our price swap derivatives. Utilizing actual derivative contractual volumes as of December 31, 2012, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability of these instruments by approximately $3,673,000, while a 10% decrease in forward curves associated with the underlying commodity would have decreased the net liability for these instruments by $3,673,000. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately $5,959,000 at December 31, 2012) and receivables from the sale of our oil and natural gas production (approximately $8,081,000 at December 31, 2012).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. 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 year ended December 31, 2011, Windsor Midstream LLC, an entity controlled by Wexford, accounted for approximately 79% of our revenue. No other customer accounted for more than 10% of our revenue during these periods.

Joint operations receivables arise from billings to 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 intend to drill. We have little ability to control whether these entities will participate in our wells. At December 31, 2012, we had one customer that represented approximately 97% of our total joint operations receivables. At December 31, 2011, we had one customer that represented approximately 68% of our total joint operations receivables.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate equal to 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. Borrowings under the credit facility bore interest at a weighted average rate of zero as of December 31, 2012 as we did not have any amounts outstanding under the credit facility. On October 17, 2012 the last date on which borrowings were outstanding under our revolving credit facility, such borrowings bore interest at a weighted average rate 3.72%. An increase or decrease of 1% in the interest rate would have a compounding decrease or increase in our net income (loss) of approximately $1,000,000, based on the $100,000,000 outstanding in the aggregate under our revolving credit facility on October 17, 2012.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 of this report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and Vice President and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Vice President and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of December 31, 2012, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Vice President and Chief Financial Officer have concluded that as of December 31, 2012, our disclosure controls and procedures are effective.

Management's Annual Report on Internal Control Over Financial Reporting and Attestation Report of the Registered Public Accounting Firm

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the company's registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information as to Item 10 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2012.

We have adopted a Code of Business Conduct and Ethics that applies to our Chief Executive Officer, Chief Financial Officer, principal accounting officer and controller and persons performing similar functions. The Code of Business Conduct and Ethics is posted on our website at http://ir.diamondbackenergy.com/governance.cfm. We intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the Code of Business Conduct and Ethics by posting such information on our website at the address specified above.

ITEM 11. EXECUTIVE COMPENSATION

Information as to Item 11 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2012.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information as to Item 12 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2012.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information as to Item 13 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2012.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information as to Item 14 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2012.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents included in this report:

1. *Financial Statements*

2. *Financial Statement Schedules*

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the Company's combined consolidated financial statements and related notes.

3. *Exhibits*

The Exhibit Index beginning on page E–1 of this report is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DIAMONDBACK ENERGY, INC.

Date:	March 1, 2013	/s/ Travis D. Stice
		Travis D. Stice
		Chief Executive Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Steven E. West Steven E. West	Chairman of the Board and Director	March 1, 2013
/s/ Travis D. Stice Travis D. Stice	Chief Executive Officer and Director	March 1, 2013
/s/ Michael P. Cross Michael P. Cross	Director	March 1, 2013
/s/ David L. Houston David L. Houston	Director	March 1, 2013
/s/ Mark L. Plaumann Mark L. Plaumann	Director	March 1, 2013
/s/ Teresa L. Dick Teresa L. Dick	Chief Financial Officer, Senior Vice President, and Assistant Secretary	March 1, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Diamondback Energy, Inc.

We have audited the accompanying combined consolidated balance sheets of Diamondback Energy, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2012 and 2011, and the related combined consolidated statements of operations, stockholders’ equity/members’ equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the combined consolidated financial statements referred to above present fairly, in all material respects, the financial position of Diamondback Energy, Inc. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 1, 2013

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Diamondback Energy, Inc. and Subsidiaries
Combined Consolidated Balance Sheets

	December 31,	
	2012	2011
Assets		
Current assets:		
Cash and cash equivalents	$ 26,358,000	$ 6,959,000
Accounts receivable:		
Joint interest and other	5,959,000	3,734,000
Oil and natural gas sales	8,081,000	839,000
Related party	772,000	12,937,000
Inventories	6,195,000	6,007,000
Deferred income taxes	1,857,000	—
Prepaid expenses and other	1,053,000	336,000
Total current assets	50,275,000	30,812,000
Property and equipment		
Oil and natural gas properties, at cost, based on the full cost method of accounting ($121,245,000 and $4,528,000 excluded from amortization at December 31, 2012 and December 31, 2011, respectively)	697,742,000	339,831,000
Other property and equipment	2,337,000	1,017,000
Accumulated depletion, depreciation, amortization and impairment	(145,837,000)	(119,699,000)
	554,242,000	221,149,000
Investments-equity method	—	10,310,000
Other assets	2,184,000	1,307,000
Total assets	$ 606,701,000	$ 263,578,000
Liabilities and Stockholders' Equity/Members' Equity		
Current liabilities:		
Accounts payable trade	$ 12,141,000	$ 8,770,000
Accounts payable-related party	18,813,000	3,230,000
Accrued capital expenditures	29,397,000	13,919,000
Other accrued liabilities	10,649,000	4,894,000
Revenues and royalties payable	3,270,000	3,165,000
Derivative instruments	4,817,000	8,320,000
Note payable-short term	145,000	—
Total current liabilities	79,232,000	42,298,000
Note payable–long term	193,000	—
Note payable–credit facility–long term	—	85,000,000
Derivative instruments-long term	388,000	6,139,000
Asset retirement obligations-long term	2,125,000	1,104,000
Deferred income taxes-noncurrent	62,695,000	—
Total liabilities	144,633,000	134,541,000
Commitments and contingencies (Note 13)		
Members' equity	—	129,037,000
Stockholders' equity:		
Common stock, $0.01 par value, 100,000,000 shares authorized, 36,986,532 issued and outstanding at December 31, 2012; zero issued and outstanding at December 31, 2011	370,000	—
Additional paid-in capital	513,772,000	—
Accumulated deficit	(52,074,000)	—
Total stockholders' equity/members' equity	462,068,000	129,037,000
Total liabilities and stockholders' equity/members' equity	$ 606,701,000	$ 263,578,000

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Combined Consolidated Statements of Operations

	Year Ended December 31,		
	2012	2011	2010
Revenues:			
Oil sales	$ 65,704,000	$ 2,582,000	$ 75,000
Oil sales - related party	—	38,873,000	21,403,000
Natural gas sales	1,369,000	1,061,000	1,400,000
Natural gas sales - related party	1,010,000	586,000	—
Natural gas liquid sales	3,839,000	3,169,000	3,564,000
Natural gas liquid sales - related party	3,040,000	1,604,000	—
Oil and natural gas services - related party	—	1,491,000	811,000
Total revenues	74,962,000	49,366,000	27,253,000
Costs and expenses:			
Lease operating expenses	15,777,000	8,470,000	3,040,000
Lease operating expenses - related party	1,016,000	2,127,000	1,549,000
Production taxes	3,404,000	574,000	354,000
Production taxes - related party	287,000	1,792,000	993,000
Gathering and transportation	124,000	53,000	106,000
Gathering and transportation - related party	300,000	149,000	—
Oil and natural gas services	—	1,207,000	228,000
Oil and natural gas services - related party	—	526,000	583,000
Depreciation, depletion and amortization	26,273,000	15,601,000	8,145,000
General and administrative expenses	9,178,000	495,000	380,000
General and administrative expenses - related party	1,198,000	3,160,000	2,656,000
Asset retirement obligation accretion expense	98,000	65,000	38,000
Total costs and expenses	57,655,000	34,219,000	18,072,000
Income from operations	17,307,000	15,147,000	9,181,000
Other income (expense)			
Interest income	3,000	11,000	34,000
Interest expense	(3,610,000)	(2,528,000)	(836,000)
Other income - related party	2,132,000	—	—
Gain (loss) on derivative instruments	2,617,000	(13,009,000)	(148,000)
Loss from equity investment	(67,000)	(7,000)	—
Total other income (expense), net	1,075,000	(15,533,000)	(950,000)
Income (loss) before income taxes	18,382,000	(386,000)	8,231,000
Provision for income taxes			
Deferred income tax provision	54,903,000	—	—
Net income (loss)	$ (36,521,000)	$ (386,000)	$ 8,231,000

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Combined Consolidated Statements of Operations - Continued

	Year Ended December 31, 2012	
Pro forma information (unaudited)		
Income before income taxes, as reported	$	18,382,000
Pro forma provision for income taxes		6,553,000
Pro forma net income	$	11,829,000
Pro forma earnings per common share		
Basic	$	0.60
Diluted	$	0.60
Pro forma weighted average common shares outstanding		
Basic		19,720,734
Diluted		19,723,774

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Combined Consolidated Statement of Stockholders' Equity/Members' Equity

	Members' Equity	Common Stock Shares	Common Stock Amount	Additional paid-in capital	Accumulated Deficit	Total
Balance, December 31, 2009	$ 84,202,000	—	$ —	$ —	$ —	$ 84,202,000
Contributions	28,508,000	—	—	—	—	28,508,000
Distributions	(5,579,000)	—	—	—	—	(5,579,000)
Net income	8,231,000	—	—	—	—	8,231,000
Balance, December 31, 2010	115,362,000	—	—	—	—	115,362,000
Contributions	13,517,000	—	—	—	—	13,517,000
Equity based compensation	544,000	—	—	—	—	544,000
Net loss	(386,000)	—	—	—	—	(386,000)
Balance December 31, 2011	129,037,000	—	—	—	—	129,037,000
Contributions	4,008,000	—	—	—	—	4,008,000
Distributions of equity method investments	(10,504,000)	—	—	—	—	(10,504,000)
Equity based compensation	873,000	—	—	—	—	873,000
Earnings prior to merger	15,553,000	—	—	—	—	15,553,000
Common shares issued upon Merger	(138,967,000)	14,697,496	147,000	138,820,000	—	—
Common shares issued upon acquisition of Gulfport properties	—	7,914,036	79,000	138,417,000	—	138,496,000
Common shares issued at initial public offering, net of offering costs	—	14,375,000	144,000	234,000,000	—	234,144,000
Stock-based compensation	—	—	—	2,535,000	—	2,535,000
Net loss subsequent to merger	—	—	—	—	(52,074,000)	(52,074,000)
Balance December 31, 2012	$ —	36,986,532	$ 370,000	$ 513,772,000	$ (52,074,000)	$ 462,068,000

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Combined Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2012	2011	2010
Cash flows from operating activities:			
Net income (loss)	$ (36,521,000)	$ (386,000)	$ 8,231,000
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Provision for deferred income taxes	54,903,000	—	—
Asset retirement obligation accretion expense	98,000	65,000	38,000
Depreciation, depletion, and amortization	26,273,000	16,104,000	8,145,000
Amortization of debt issuance costs	494,000	250,000	163,000
(Gain) loss on derivative instruments	(2,617,000)	13,009,000	148,000
Loss from equity investment	67,000	—	—
Equity-based compensation expense	3,482,000	544,000	—
Gain on sale of assets	(37,000)	(23,000)	(5,000)
Changes in operating assets and liabilities:			
Accounts receivable	(5,036,000)	(1,547,000)	(1,822,000)
Accounts receivable-related party	6,096,000	(4,133,000)	(6,793,000)
Inventories	(639,000)	(872,000)	(4,897,000)
Prepaid expenses and other	(606,000)	(202,000)	(326,000)
Accounts payable and accrued liabilities	7,151,000	2,656,000	1,954,000
Accounts payable and accrued liabilities-related party	(1,218,000)	830,000	(409,000)
Revenues and royalties payable	105,000	2,666,000	499,000
Revenues and royalties payable-related party	(2,303,000)	2,037,000	266,000
Net cash provided by operating activities	49,692,000	30,998,000	5,192,000
Cash flows from investing activities:			
Additions to oil and natural gas properties	(102,122,000)	(58,160,000)	(7,624,000)
Additions to oil and natural gas properties-related party	(9,675,000)	(22,014,000)	(36,950,000)
Acquisition of Gulfport properties	(63,590,000)	—	—
Proceeds from sale of oil and natural gas properties	—	—	1,250,000
Purchase of other property and equipment	(1,102,000)	(7,065,000)	(11,741,000)
Proceeds from sale of property and equipment	48,000	55,000	20,000
Settlement of non-hedge derivative instruments	(8,963,000)	(4,127,000)	(3,963,000)
Receipt on derivative margins	2,326,000	4,203,000	3,772,000
Deconsolidation of Bison	—	(10,000)	—
Proceeds from sale of membership interest in equity investment	—	6,010,000	—
Net cash used in investing activities	(183,078,000)	(81,108,000)	(55,236,000)
Cash flows from financing activities:			
Proceeds from borrowings on credit facility	15,000,000	40,233,000	61,066,000
Repayment on credit facility	(100,000,000)	—	(23,950,000)
Proceeds from note payable- related party	30,000,000	—	—
Payment of note payable- related party	(30,050,000)	—	—
Debt issuance costs	(450,000)	(770,000)	(718,000)
Initial public offering costs	(2,887,000)	(30,000)	—
Proceeds from initial public offering	237,164,000	—	—
Contributions by members	4,008,000	13,517,000	20,914,000
Distributions to members	—	—	(5,579,000)
Net cash provided by financing activities	152,785,000	52,950,000	51,733,000
Net increase in cash and cash equivalents	19,399,000	2,840,000	1,689,000
Cash and cash equivalents at beginning of period	6,959,000	4,119,000	2,430,000
Cash and cash equivalents at end of period	$ 26,358,000	$ 6,959,000	$ 4,119,000

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Combined Consolidated Statements of Cash Flows - Continued

	Year Ended December 31,		
	2012	2011	2010
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$ 3,017,000	$ 2,265,000	$ 600,000
Supplemental disclosure of non-cash transactions:			
Asset retirement obligation incurred, including changes in estimate	$ 386,000	$ 297,000	$ 223,000
Distribution of equity method investments	$ 10,504,000	$ —	$ —
Note payable exchanged for equipment	$ 411,000	$ —	$ —
Property Contributed	$ —	$ —	$ 7,594,000
Common stock issued as a result of the Gulfport transaction	$ 138,496,000	$ —	$ —
Asset retirement obligation acquired as a result of the Gulfport transaction	$ 562,000	$ —	$ —
Post-closing adjustment payable as a result of the Gulfport transaction	$ 18,550,000	$ —	$ —

See accompanying notes to combined consolidated financial statements.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Description of the Business

Diamondback Energy, Inc. ("Diamondback" or the "Company") together with its subsidiaries, is an independent oil and 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. 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 (the "Merger"). Prior to the Merger, Diamondback Energy LLC was a holding company and did not conduct any material business operations other than its ownership of the Company's common stock and the membership interests in Windsor Permian LLC ("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 ("Wexford"), our equity sponsor, caused all of the outstanding equity interests in Windsor UT LLC ("Windsor UT") to be contributed to Windsor Permian prior to the Merger in a transaction referred 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, Diamondback acquired from Gulfport Energy Corporation ("Gulfport") all of its oil and natural gas interests in the Permian Basin (the "Gulfport properties") in exchange for shares of Diamondback common stock and a promissory note in a transaction referred 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. See Note 2—Acquisitions for information regarding the acquisition.

On October 17, 2012, the Company completed its initial public offering ("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 the Company 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.

Basis of Presentation

Transfers of a business between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information. As discussed above, the Windsor UT contribution was accounted for as a transaction between entities under common control thus the accompanying combined consolidated financial statements and related notes of the Company have been retrospectively adjusted to include the historical results of Windsor UT at historical carrying values and their operations as if they were combined for all periods presented. The accompanying financial statements and related notes presented herein represent the combined financial position of our Predecessors for periods prior to October 11, 2012, the combined results of operations, cash flows and equity of our Predecessors through October 11, 2012, and the Company and its wholly-owned subsidiaries consolidated financial position, results of operations, cash flows and equity subsequent to October 11, 2012. All intercompany balances and transactions are eliminated in consolidation.

Use of Estimates

Certain amounts included in or affecting the Company's combined consolidated financial statements and related disclosures must be estimated by management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the combined consolidated financial statements are prepared. These estimates and assumptions affect the amounts the Company reports for assets and liabilities and the Company's disclosure of contingent assets and liabilities at the date of the combined consolidated financial statements. Actual results could differ from those estimates.

The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, asset retirement obligations, the fair value determination of acquired assets and liabilities, stock-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

Reclassifications

The Company has reclassified certain prior year amounts to conform with the current year's presentation. In the 2011 combined consolidated balance sheet, $92,000 of prepaid costs related to oil and natural gas properties has been reclassified from "Prepaid expenses and other" to "Other assets".

Cash and Cash Equivalents

The Company considers all highly liquid investments purchased with a maturity of three months or less and money market funds to be cash equivalents.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2012 or December 31, 2011.

Derivative Instruments

The Company is required to recognize its derivative instruments on the combined consolidated balance sheets as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the realized and unrealized change in fair value on derivative instruments in the combined consolidated statements of operations.

Fair Value of Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, receivables, payables, derivatives and notes payable. The carrying amount of cash and cash equivalents, receivables and payables approximates fair value because of the short-term nature of the instruments. The fair value of the revolving credit facility approximates its carrying value based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities. The note payable is carried at cost, which approximates fair value due to the nature of the instrument and relatively short maturity. Derivatives are recorded at fair value (see Note 12—Fair Value Measurements).

Oil and Natural Gas Properties

The Company accounts for its 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. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities are charged to expense as they are 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. Any income from services provided by subsidiaries to working interest owners of properties in which the Company also owns an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties proportionate to the Company's investment in the subsidiary (see Note 5—Equity Method Investments). 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 $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 was $25,772,000, $15,377,000 and $7,373,000 for the years ended December 31, 2012, 2011 and 2010, respectively.

Under the full-cost method of accounting, the net book value of oil and natural gas properties, less related deferred income taxes, may not exceed a calculated "ceiling". The ceiling limitation is the estimated after-tax future net cash flows from proved oil and natural gas reserves, discounted at 10%. Estimated future net cash flows exclude future cash flows associated with settling accrued asset retirement obligations. Estimated future net cash flows are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production. Any excess of the net book value of proved oil and natural gas properties, less related deferred income taxes, over the ceiling is charged to expense. No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2012, 2011 or 2010.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on an annual basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Other Property and Equipment

Other property and equipment is recorded at cost. The Company expenses maintenance and repairs in the period incurred. Upon retirements or disposition of assets, the cost and related accumulated depreciation are removed from the combined consolidated balance sheet with the resulting gains or losses, if any, reflected in operations. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years. Depreciation expense was $501,000, $727,000 and $772,000 for the years ended December 31, 2012, 2011 and 2010, respectively.

Asset Retirement Obligations

The Company measures the future cost to retire its tangible long-lived assets and recognizes such cost as a liability in accordance with ASC Topic 410, *Asset Retirement and Environmental Obligations* ("ASC Topic 410"), which provides accounting and reporting guidance for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction or normal operation of a long-lived asset.

ASC Topic 410 requires companies to record a liability relating to the retirement and removal of assets used in their businesses. For the Company, asset retirement obligations represent the future abandonment costs of tangible assets, namely wells. ASC Topic 410 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred if a reasonable estimate of fair value can be made and that the corresponding cost be capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, the difference is recorded in oil and natural gas properties.

Impairment of Long-Lived Assets

Other property and equipment used in operations are reviewed whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss is recognized only if the carrying amount of a long-lived asset is not recoverable from its estimated future undiscounted cash flows. An impairment loss is the difference between the carrying amount and fair value of the asset. The Company had no such impairment losses for the years ended December 31, 2012, 2011 or 2010.

Capitalized Interest

The Company capitalizes interest on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. Capitalized interest cannot exceed gross interest expense. During the years ended December 31, 2012 and 2011, the Company did not capitalize any interest expense and during the year ended December 31, 2010, the Company capitalized $150,000 of interest expense.

Inventories

Inventories are stated at the lower of cost or market and consist of the following:

	December 31,	
	2012	2011
Tubular goods and equipment	$ 5,725,000	$ 5,631,000
Crude oil	470,000	376,000
	$ 6,195,000	$ 6,007,000

The Company's tubular goods and equipment is primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units. The inventory is primarily acquired for use in future drilling or repair operations and is carried at lower of cost or market. "Market", in the context of inventory valuation, represents net realizable value, which is the amount that the Company is allowed to bill to the joint accounts under joint operating agreements to which the Company is a party. As of December 31, 2012, the Company estimated that all of its tubular goods and equipment will be utilized within one year. The total inventory includes tubular goods held by others of zero at December 31, 2012 and $1,094,000 at December 31, 2011.

Debt issuance costs

The Company amortizes debt issuance costs related to its credit facility as interest expense over the scheduled maturity period of the debt. Unamortized debt issuance costs were $1,115,000 and $1,168,000 as of December 31, 2012 and December 31, 2011, respectively. The Company includes the unamortized costs in other assets in its combined consolidated balance sheets.

Revenue and Royalties Payable

For certain oil and natural gas properties, where the Company serves as operator, the Company receives production proceeds from the purchaser and further distributes such amounts to other revenue and royalty owners. Production proceeds applicable to other revenue and royalty owners are reflected as revenue and royalties payable in the accompanying combined consolidated balance sheets. The Company recognizes revenue for only its net revenue interest in oil and natural gas properties.

Revenue Recognition

Oil and natural gas revenues are recorded when title passes to the purchaser, net of royalty interests, discounts and allowances, as applicable. The Company accounts for oil and natural gas production imbalances using the sales method, whereby a liability is recorded when the Company's overtake volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where the Company has taken less than its ownership share of production. The Company did not have any gas imbalances as of December 31, 2012 or December 31, 2011. Revenues from oil and natural gas services are recognized as services are provided.

Investments

Equity investments in which the Company exercises significant influence but does not control are accounted for using the equity method. Under the equity method, generally the Company's share of investees' earnings or loss is recognized in the statement of operations. The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company would recognize an impairment provision. There was no impairment for the Company's equity investments for the years ended December 31, 2012 or December 31, 2011. For additional information on the Company's investments, see Note 5—Equity Method Investments.

Accounting for Stock-Based Compensation

The Company accounts for stock-based compensation in accordance with the provisions of ASC Topic 718, "Compensation—Stock Compensation". The Company grants various types of stock-based awards including stock options and restricted stock units. These plans and related accounting policies are defined and described more fully in Note 8—Stock and Equity Based Compensation. Stock compensation awards are measured at fair value on the date of grant and are expensed, net of estimated forfeitures, over the required service period.

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the year ended December 31, 2012, three purchasers accounted for more than 10% of our revenue: Plains Marketing, LP (53%); Occidental Energy Marketing, Inc. (16%); and Andrews Oil Buyers, Inc. (10%). For the years ended December 31, 2011 and December 31, 2010, Windsor Midstream LLC, a related party, accounted for 79% of the Company's revenue in both periods. The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Environmental Compliance and Remediation

Environmental compliance and remediation costs, including ongoing maintenance and monitoring, are expensed as incurred. Liabilities are accrued when environmental assessments and remediation are probable, and the costs can be reasonably estimated.

Income Taxes

Diamondback uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The Company and the Predecessor are subject to margin tax in the state of Texas. During the years ended December 31, 2012, 2011 and 2010 there was no margin tax expense. The Company's 2008, 2009, 2010 and 2011 federal income tax and state margin tax returns remain open to examination by tax authorities. As of December 31, 2012 and December 31, 2011, the Company had no unrecognized tax benefits that would have a material impact on the effective rate. The Company is continuing its practice of recognizing interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. During the years ended December

31, 2012, 2011 and 2010 there was no interest or penalties associated with uncertain tax positions recognized in the Company's combined consolidated financial statements.

Unaudited Pro Forma Income Taxes

Diamondback Energy, Inc. was formed as a holding company on December 30, 2011, and did not conduct any material business operations prior to the Merger. Diamondback Energy, Inc. is a C-Corp under the Internal Revenue Code and is subject to income taxes. The Company computed a pro forma income tax provision as if the Company and the Predecessors were subject to income taxes since December 31, 2011. 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.

Unaudited Pro Forma Earnings per Share

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 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.

New Pronouncements Issued but Not Yet Adopted

In December 2011, the FASB issued Accounting Standards Update No. 2011-11, *Disclosures about Offsetting Assets and Liabilities*. In January 2013, the FASB issued Accounting Standards Update No. 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*. The guidance in ASU No. 2013-01 limits the scope of the new balance sheet offsetting disclosures to derivatives, repurchase agreements and securities lending transactions to the extent that they are (1) offset in the financial statements or (2) subject to an enforceable master netting arrangement or similar agreement. The disclosures are required to enable users of financial statements to understand significant quantitative differences in balance sheets prepared in accordance with accounting principles generally accepted in the U.S. ("GAAP") and International Financial Reporting Standards related to the offsetting of financial instruments. The existing GAAP guidance allowing balance sheet offsetting, including industry-specific guidance, remains unchanged. The guidance in ASU No. 2011-11and ASU No. 2013-01 is effective for annual and interim reporting periods beginning on or after January 1, 2013. The disclosures should be applied retrospectively for all prior periods presented. The Company does not expect the adoption of this guidance to have a significant impact on its financial position, results of operations or cash flow.

2. ACQUISITIONS

On May 7, 2012, the Company entered into an agreement with Gulfport in which Gulfport agreed to sell to the Company, subject to certain conditions, all of its oil and natural gas interests in the Permian Basin in exchange for shares of the Company's common stock and a promissory note in a transaction referred to as the Gulfport transaction, with such consideration being subject to a post-closing adjustment. The Gulfport transaction was completed on October 11, 2012 for the purpose of expanding the Company's acreage position. The acquisition was accounted for according to the guidance provided in ASC 805, Business Combinations, which requires application of the acquisition method. This methodology requires the recording of net assets acquired and consideration transferred at fair value.

The acquisition-date fair value of the consideration transferred totaled $220,636,000, which consisted of the following:

Common Stock (7,914,036 shares)	$	138,496,000
Promissory note paid in full from IPO proceeds		63,590,000
Closing adjustment payable		18,550,000
Total	$	220,636,000

The fair value of the 7,914,036 common shares issued was determined based on the IPO pricing of $17.50 per common share on October 11, 2012. The closing adjustment payable balance is a result of the working capital adjustment.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the acquisition date. As shown above, consideration transferred in the transaction was $220,636,000, resulting in no goodwill or bargain purchase gain.

Proved oil and natural gas properties	$	115,760,000
Unevaluated oil and natural gas properties		111,373,000
Asset retirement obligations		(562,000)
Deferred income tax liability		(5,935,000)
Total fair value of net assets	$	220,636,000

The Company has included in its combined consolidated statements of operations revenues of $7,353,000 and direct operating expenses of $2,260,000 for the period from October 11, 2012 to December 31, 2012 due to the acquisition. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion. The following unaudited summary pro forma combined consolidated statement of operations data of Diamondback for the years ended December 31, 2012 and 2011 has been prepared to give effect to the acquisition as if it had occurred on January 1, 2011. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisition occurred on January 1, 2011. The pro forma data also necessarily exclude various operation expenses related to the Gulfport properties and the financial statements 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.

	Pro Forma (Unaudited) Year Ended December 31,	
	2012	**2011**
Pro forma total revenues	$ 97,455,000	$ 72,418,000
Pro forma income from operations	24,064,000	23,189,000
Pro forma net income (loss)	(29,764,000)	7,666,000 (1)

(1) For 2011, this amount does not include a pro forma income tax provision relating to becoming subject to income taxes as a result of the Merger.

3. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	December 31, 2012	December 31, 2011
Oil and natural gas properties:		
Subject to depletion	$ 576,497,000	$ 335,303,000
Not subject to depletion-acquisition costs		
Incurred in 2012	117,395,000	—
Incurred in 2011	1,670,000	1,689,000
Incurred in 2010	1,647,000	2,306,000
Incurred in 2009	533,000	533,000
Total not subject to depletion	121,245,000	4,528,000
Gross oil and natural gas properties	697,742,000	339,831,000
Less accumulated depreciation, depletion, amortization and impairment	(145,102,000)	(119,366,000)
Oil and natural gas properties, net	552,640,000	220,465,000
Other property and equipment	2,337,000	1,017,000
Less accumulated depreciation	(735,000)	(333,000)
Other property and equipment, net	1,602,000	684,000
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 554,242,000	$ 221,149,000

Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized internal costs were approximately $4,872,000, $871,000 and zero for the years ended December 31, 2012, 2011 and 2010, respectively. Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed within three to five years.

4. ASSET RETIREMENT OBLIGATION

The following table describes the changes to the Company's ARO liability for the following periods:

	Year Ended December 31, 2012	2011	2010
Asset retirement obligation, beginning of period	$ 1,104,000	$ 742,000	$ 482,000
Additional liability incurred	201,000	297,000	222,000
Liabilities acquired	562,000	—	—
Liabilities settled	(5,000)	—	—
Accretion expense	98,000	65,000	38,000
Revisions in estimated liabilities	185,000	—	—
Asset retirement obligation, end of period	2,145,000	1,104,000	742,000
Less current portion	20,000	—	—
Asset retirement obligations - long-term	$ 2,125,000	$ 1,104,000	$ 742,000

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company estimates the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance.

During 2012, the Company recorded $562,000 in additional abandonment liabilities on properties acquired in the Gulfport transaction. Increases in estimated costs to plug and abandon the properties resulted in an upward revision of $185,000.

5. EQUITY METHOD INVESTMENTS

Bison Drilling and Field Services LLC

On November 15, 2010, the Company had formed a wholly owned subsidiary, Bison Drilling and Field Services LLC ("Bison"), formerly known as Windsor Drilling LLC. In addition, on March 2, 2010, the Company had formed a wholly owned subsidiary, West Texas Field Services LLC, which, on January 1, 2011, contributed all of its assets and liabilities to Bison and West Texas Field Services LLC was subsequently dissolved on June 12, 2012. Bison owned and operated drilling rigs and various oil and natural gas well servicing equipment.

Beginning on March 31, 2011, various related party investors contributed capital to Bison diluting the Company's ownership interest. The Company assessed its ability to exercise financial control over Bison and based on the results of its assessment, the Company concluded it maintained significant influence but it no longer had the ability to exercise control over Bison. The Company deconsolidated Bison for financial reporting purposes as of March 31, 2011 and the previously consolidated amounts were removed from the combined consolidated balance sheet and reflected as an equity method investment. The Company eliminated intercompany profits or losses in relation to its continuing involvement with Bison, proportionate to its equity interest. Under the equity method, generally the Company's share of investees' earnings or loss is recognized in the combined consolidated statements of operations. However, because substantially all of Bison's earnings were generated by performing services on properties owned and operated by the Company, the Company's share of Bison's earnings have been credited to oil and natural gas properties.

An entity is required to deconsolidate a subsidiary when the entity ceases to have a controlling financial interest in the subsidiary. Upon deconsolidation of a subsidiary, an entity recognizes a gain or loss on the transaction and measures any retained investment in the subsidiary at fair value. The gain or loss includes any gain or loss associated with the difference between the fair value of the retained investment in the subsidiary and its carrying amount at the date the subsidiary is deconsolidated.

The Company internally reviewed the balance sheet of Bison to determine its fair value. At the time of the transaction Bison was still a recently formed company and had not yet built value in its operations. Bison's assets consisted primarily of four recently purchased drilling rigs. Two of the drilling rigs were purchased at market price from a third party in December 2010 and the second two were purchased from the same third party in April 2011. The Company also reviewed pricing of similar rigs in the market through retail and auction transactions. Because the rigs had just recently been purchased and this purchase price was in line with other outside transactions the Company determined that Bison's book value equaled fair value. There was no gain or loss recorded and the retained investment was recorded at fair value which equaled book value.

In September 2011, the Company completed the sale of 25% of its membership interest in Bison to a related party. The Company internally reviewed the fair value of Bison and because the effective date of this transaction was May 1, 2011 and was within thirty days of the above valuation the Company concluded the value of Bison had not changed. The Company determined that fair value equaled book value at the date of this transaction. There was no gain or loss recorded and the retained investment was recorded at fair value which equaled book value.

As of December 31, 2011, the Company had a 27.7% ownership in Bison. The table below summarizes financial information for Bison as of December 31, 2011.

	December 31, 2011
Current Assets	$ 4,438,000
Property and equipment, net	21,708,000
Other assets	880,000
Current liabilities	2,419,000
Equity	24,607,000

As of June 15, 2012, the Company distributed its remaining interest in Bison to an entity which is controlled and managed by Wexford. As the transaction was between entities under common control, the Company has recognized the distribution of $6,437,000 as an equity transaction. Bison continues to be a related party with the Company.

Muskie Holdings LLC
During 2011, the Company paid approximately $4,200,000 for land and various other capital items related to the land. On October 7, 2011, the Company contributed these assets to a newly formed entity, Muskie Holdings LLC, a Delaware limited liability company, for a 48.6% equity interest. Through additional contributions to Muskie from a related party and various Wexford portfolio companies, the Company's interest in Muskie decreased to 33% as of June 15, 2012. Muskie generated a loss during the period January 1, 2012 through June 15, 2012 and the Company has recorded its share of this loss.

The table below summarizes financial information for Muskie as of December 31, 2011.

	December 31, 2011
Current assets	$ 994,000
Property and equipment, net	7,585,000
Current liabilities	27,000
Equity	8,552,000

As of June 15, 2012, the Company distributed its remaining interest in Muskie to an entity which is controlled and managed by Wexford. As the transaction was between entities under common control, the Company has recognized the distribution of $4,067,000 as an equity transaction. Muskie continues to be a related party with the Company.

6. DEBT

Credit Facility-Wells Fargo Bank

On October 15, 2010, the Company entered into a secured loan agreement with BNP Paribas ("BNP") as the administrative agent, sole book runner and lead arranger, as amended, providing for a revolving credit facility. On May 10, 2012, the revolving credit agreement was further amended to provide for the resignation of BNP, and the appointment of Wells Fargo Bank, National Association, as administrative agent for the lenders. The aggregate maximum credit amount under the revolving credit agreement is $250.0 million notwithstanding future redeterminations of the borrowing base. The outstanding borrowings bear interest at a rate elected by the Company 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.

Principal may be optionally repaid from time to time and is required to be paid (i) if the loan amount exceeds the borrowing base and (ii) at the maturity date of October 15, 2014. The Company is obligated to pay, quarterly, a commitment fee equal to 0.5% per year of the unused portion of the borrowing base. The loan is secured by substantially all of the Company's assets. The borrowing base is re-determined semi-annually with effective dates of April 1st and October 1st (a "scheduled redetermination"). In addition, the Company may request an additional three redeterminations of the borrowing base during any 12 months period. The borrowing base was $45.0 million at December 31, 2010. The borrowing base increased throughout 2011 through various redeterminations and at

December 31, 2011 the borrowing base was $100.0 million. The borrowing base increased in 2012 through redeterminations and at December 31, 2012 the borrowing base was $135.0 million. In connection with the IPO, the Company repaid all outstanding borrowings under its revolving credit facility and as of December 31, 2012 had no outstanding borrowings. As of December 31, 2011, the Company had outstanding borrowings of $85.0 million which bore a weighted average interest rate of 3.30%.

The agreement contains various affirmative and restrictive covenants. These covenants, among other things, prohibit additional indebtedness, sales of assets, mergers and consolidations, dividends and distributions, and changes in management and require the maintenance of various financial ratios defined below.

The current lenders and their percentage commitments in the revolving credit facility are Wells Fargo Bank, N.A. (45%), Amegy Bank, N.A. (25%), U.S. Bank, N.A. (25%) and West Texas National Bank (5%).

As of July 24, 2012, the revolving credit agreement was amended and restated to include Diamondback Energy LLC and its subsidiaries as additional guarantors to the facility. The covenant prohibiting additional indebtedness was also amended to allow the issuance of unsecured debt of up to $250.0 million and, in connection with any such issuance, the reduction of the borrowing base by 25% of the principal amount of such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. The amendment also provided that redemptions of any unsecured debt will be restricted unless certain liquidity requirements are met. Further, the amendment modified certain financial ratios, the current requirements of which are described below.

Financial Covenant	Required Ratio
Ratio of EBITDAX to interest expense, as defined in the credit agreement	Not less than 2.5 to 1.0
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of debt under revolving credit agreement to EBITDAX	Not greater than 3.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

The revolving credit agreement defines EBITDAX, for any period, as the sum of consolidated net income for such period plus the following expenses or charges to the extent deducted from consolidated net income for such period: interest; income taxes; depreciation, depletion, amortization and exploration expenses; extraordinary items and other similar non-cash charges, including expenses related to stock-based compensation and hedging, minus all non-cash income added to consolidated net income.

As of July 31, 2012, the first amendment to the amended and restated credit agreement was executed, which provided for the issuance to Gulfport of the Gulfport transaction note and the payment of the Gulfport transaction note from the proceeds of the IPO.

As of September 28, 2012, the second amendment to the amended and restated credit agreement was executed, which among other things provided for an increase in permitted subordinated debt in a maximum principal amount not to exceed $45.0 million, including any such indebtedness evidenced by the Company's subordinated note with an affiliate of Wexford described in more detail under "-Subordinated Note" below, waived compliance with the Company's current ratio covenant for the quarter ending September 30, 2012 and increased the aggregate limitation on lease payments during any period of 12 months consecutive calendar months from $250,000 to $550,000.

As of December 31, 2012 and December 31, 2011, the Company was in compliance with all financial covenants under the revolving credit facility. The lenders may accelerate all of the indebtedness under the revolving credit facility upon the occurrence of any event of default unless the Company cures any such default within any applicable grace period. For payments of principal and interest under the revolving credit facility, the Company generally has a three business day grace period, and a 30-day cure period for most covenant defaults, but not for defaults of certain specific covenants, including the financial covenants and negative covenants.

Subordinated Note

Effective May 14, 2012, the Company 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 further capital support to the Company. In connection with the IPO, the Company repaid all outstanding borrowings under the subordinated note and the subordinated note was canceled.

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 the 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 an initial public offering. Any indebtedness evidenced by this note was subordinate in the right of payment to any indebtedness outstanding under the Company's revolving credit facility.

Note Payable

The Company entered into an installment payment contract with EMC Corporation for the purchase of computer equipment. The contract is payable in equal installments over a period of 36 months. As of December 31, 2012, there was $338,000 outstanding under this note.

7. STOCKHOLDERS' EQUITY & PRO FORMA EARNINGS PER SHARE

Common Stock Offering

On October 11, 2012, the Company priced 12,500,000 shares of common stock in the IPO at $17.50 per share, and on October 12, 2012, shares of the Company's common stock began trading on the Nasdaq Global Select Market under the symbol "FANG". On October 17, 2012, the Company closed the IPO. On October 23, 2012, the underwriters purchased an additional 1,875,000 shares of common stock following the exercise in full of the over-allotment option. The Company 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.

The authorized capital stock of the Company consists of 100.0 million shares of common stock, par value $0.01 per share, and 10.0 million shares of preferred stock, par value $0.01 per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors. At December 31, 2012, there were no shares of preferred stock outstanding.

Unaudited Pro Forma Earnings Per Share

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 were outstanding for the entire year. Certain options to purchase shares of the Company's common stock were excluded from the dilution calculation because the options were antidilutive. A reconciliation of the components of pro forma basic and diluted earnings per common share is presented in the table below:

	2012		
	Income	**Shares**	**Per Share**
Basic:			
Pro forma net income attributable to common stock	$ 11,829,000	19,720,734	$ 0.60
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$ —	3,040	
Diluted:			
Pro forma net income attributable to common stock	$ 11,829,000	19,723,774	$ 0.60

8. STOCK AND EQUITY BASED COMPENSATION

On October 10, 2012, the Board of Directors approved the Diamondback Energy, Inc. 2012 Equity Incentive Plan (the "2012 Plan"), which is intended to provide eligible employees with equity-based incentives. The 2012 Plan provides for the granting of incentive stock options, nonstatutory stock options, restricted awards (restricted stock and restricted stock units), performance awards, and stock appreciation rights, or any combination of the foregoing. A total of 2.5 million shares of the Company's common stock has been reserved for issuance pursuant to this plan. Previous to the 2012 Plan, each of the Company's Executive Officers was provided with an option to acquire a percentage membership interest in Windsor Permian. In connection with the IPO and the 2012 Plan, these options were canceled and replaced with the right to receive a cash payment, restricted stock units and stock options. Such grant of new awards is deemed to be a modification of old awards and was accounted for as a modification of the original awards. The modification date for these awards was October 11, 2012 which was the date of IPO pricing of $17.50 per share. Eight employees were affected by this modification. As a result of the modification, incremental compensation cost of $4,588,000 was recognized on the modification date to recognize the portion of awards that are vested and includes cash payments of $2,813,000. In addition to the compensation expense recognized on the modification date, $5,866,000 of compensation expense will be recognized over the remaining service period and a liability of $333,000 will be recognized ratably over one year as the Company's chief executive officer is entitled to receive a cash payment on the first anniversary date of the IPO, subject to his continued employment with the Company. The modification did not change the original vesting or exercise periods. As a result, options vest in four equal annual installments commencing on the first anniversary of the original date of grant and are exercisable for 5 years from the original date of grant.

The following table presents the effects of the equity and stock-based compensation plans and related costs:

	2012	2011
General and administrative expenses	$ 3,757,000	$ 438,000
Stock-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	2,537,000	106,000
Related income tax benefit	930,000	—

Stock Options

In accordance with the 2012 Plan, the exercise price of stock options granted may not be less than the market value of the stock at the date of grant. The shares issued under the 2012 Plan will consist of new shares of Company stock. Unless otherwise specified in an agreement, options become exercisable ratably over a five-year period. However, as described above, options associated with the modification vest in four equal annual installments and are exercisable for 5 years from the date of grant.

The fair value of the stock options on the date of grant is expensed over the applicable vesting period. The Company estimates the fair values of stock options granted using a Black-Scholes option valuation model, which requires the Company to make several assumptions. The Company does not have a long history of market prices, thus the expected volatility was determined using the historical volatility for a peer group of companies. The expected term of options granted was determined based on the contractual term of the awards and remaining vesting term at the modification date. The risk-free interest rate is based on the U.S. treasury yield curve rate for the expected term of the option at the date of grant. The Company does not anticipate paying cash dividends; therefore, the expected dividend yield was assumed to be zero. All such amounts represent the weighted-average amounts for each year.

	2012
Grant-date fair value	$ 4.41
Expected volatility	40.0%
Expected dividend yield	0.0%
Expected term (in years)	3.8
Risk-free rate	0.33%

The following table presents a summary of the Company's outstanding stock options.

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term (In years)	Intrinsic Value
Outstanding at December 31, 2011	—	$ —		
Granted	850,000	$ 17.50		
Exercised	—	$ —		
Outstanding at December 31, 2012	850,000	$ 17.50	3.58	$ 1,377,000
Vested and Expected to vest at December 31, 2012	850,000	$ 17.50	3.58	$ 1,377,000
Exercisable at December 31, 2012	212,500	$ 17.50	3.55	$ 344,000

As of December 31, 2012, the unrecognized compensation cost related to unvested stock options was $2,462,000. Such cost is expected to be recognized over a weighted-average period of 2.6 years.

Restricted Stock Awards and Units

Through the 2012 Plan, approved by the Board of Directors, the Company has restricted stock and restricted stock unit plans for eligible employees. The Company estimates the fair values of restricted stock awards and units as the closing price of the Company's common stock on the grant date of the award, which is expensed over the applicable vesting period. The following table presents a summary of the Company's restricted stock awards and units.

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2011	—	$ —
Granted	279,046	$ 17.50
Vested	(72,539)	$ 17.50
Forfeited	—	$ —
Unvested at December 31, 2012	206,507	$ 17.50

The aggregate fair value of restricted stock awards and units that vested during 2012 was $1,269,000. As of December 31, 2012, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $3,228,000. Such cost is expected to be recognized over a weighted-average period of 2.5 years.

Equity-Based Compensation

During the year ended December 31, 2011, Windsor Permian granted to its executive officers options to acquire membership interests in Windsor Permian. Such options vested in four equal annual installments commencing on the first anniversary of the date of grant and were exercisable for 5 years from the date of grant. Summarized below are the grant dates with the total exercise prices and total fair values of the underlying options:

Grants Made During the Months Ended	Membership Interest Granted	Exercise Price	Fair Value at Date of Grant
April 2011	1.00%	$ 3,600,000	$ 1,453,000
August 2011	1.20%	6,000,000	1,384,000
September 2011	1.25%	5,900,000	1,533,000
November 2011	0.25%	1,250,000	288,000
	3.70%	$ 16,750,000	$ 4,658,000

At December 31, 2011, for outstanding options, the intrinsic value was $113,000 and the weighted-average remaining contractual terms were 4.6 years. Also, at December 31, 2011, no options were exercisable.

The Company accounted for such options issued using a fair-value-based method calculated on the grant-date of the award. The resulting cost was recognized on a straight-line basis over the vesting period of the entire option.

The fair value of the options issued was estimated using the Black-Scholes option-pricing model. One of the inputs to this model was the estimate of the fair value of the underlying membership interest on the date of grant. The other inputs include an estimate of the expected volatility of the membership interest, an option's expected term, the risk-free interest rate over the option's expected term, the option's exercise price, and expectations regarding dividends.

Windsor Permian did not have a history of market prices for its membership interests because such interests were not publicly traded. The expected volatility was determined using the historical volatility for a peer group of companies. The expected term for options issued was determined based on the contractual term of the awards. The weighted-average risk-free interest rate was based on the daily U.S. treasury yield curve rate whose term was consistent with the expected life of the options. Windsor Permian did not anticipate paying cash dividends; therefore, the expected dividend yield was assumed to be zero.

A summary of the significant assumptions used to estimate the fair value of the options to acquire membership interests during the year ended December 31, 2011 was as follows:

Expected term	5 years
Risk-free interest rate	0.96%
Expected volatility	45.5%
Expected dividend yield	0.00%

These equity-based awards were canceled and replaced with the right to receive a cash payment, restricted stock units and stock options as described in the above sections of this Note.

9. RELATED PARTY TRANSACTIONS

Administrative Services

An entity under common management provided technical, administrative and payroll services to the Company under a shared services agreement which began March 1, 2008. Through December 31, 2011, amounts charged to the Company included those costs directly attributable to the Company as well as indirect costs allocated to the Company. The reimbursement amount for indirect costs is determined by the affiliate's management based on estimates of time devoted to the Company. During the years ended December 31, 2012, 2011 and 2010, the Company incurred total costs of $4,419,000, $10,110,000 and $7,996,000, respectively. Costs incurred unrelated to drilling activities are expensed and costs incurred in the acquisition, exploration and development of proved oil and natural gas properties have been capitalized. The expensed costs were partially offset in general and administrative expenses by overhead reimbursements of $2,548,000, $1,954,000 and $1,389,000 for the years ended December 31, 2012, 2011 and 2010, respectively. As of December 31, 2012, the Company owed the administrative services affiliate $13,000 and as of December 31, 2011, the Company owed the administrative services affiliate $773,000. These amounts are included in accounts payable-related party in the accompanying combined consolidated balance sheets.

Effective January 1, 2012, the Company entered into an additional shared services agreement with this entity. Under this agreement, the Company provides this entity and, at its request, certain affiliates, with consulting, technical and administrative services. The initial term of the additional shared services agreement is two years. Upon expiration of the initial term the agreement will continue on a month-to-month basis until canceled by either party upon thirty days prior written notice. Costs that are attributable to and billed to other affiliates are reported as other income-related party. For the year ended December 31, 2012, the affiliate reimbursed the Company $2,132,000 for services under the shared services agreement and at December 31, 2012, the affiliate owed the Company $1,000 and this amount is included in accounts receivable-related party in the accompanying combined consolidated balance sheets.

Operating Services

The Company is the operator of substantially all of its properties. As operator of these properties, the Company is responsible for the daily operations, monthly operation billings and monthly revenue disbursements for the properties.

As of December 31, 2012, the Company had no amounts due to affiliated parties related to operating services of the properties. As of December 31, 2011, the Company had an amount due to an affiliated party related to revenue distributions payable of $2,303,000. This amount is included in accounts payable-related party in the accompanying combined consolidated balance sheets. This affiliated party was an affiliate of Wexford.

As of December 31, 2012 and December 31, 2011, amounts due from an affiliate related to joint interest billings and included in accounts receivable-related party in the accompanying combined consolidated balance sheets are $742,000 and $8,590,000, respectively. This affiliated party was an affiliate of Wexford.

Drilling Services

Bison has performed drilling and field services for the Company under master drilling agreements. Under the Company's master drilling agreement with Bison, effective as of January 1, 2012, Bison committed to accept orders from the Company for the use of at least two of its rigs, and at December 31, 2012 was providing drilling services to the Company using four of its rigs. This master drilling agreement is 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 the termination of the master drilling agreement. For the three months ended March 31, 2011, Bison was a wholly-owned subsidiary and intercompany amounts were eliminated in consolidation. The Company owed Bison $120,000 as of December 31, 2012 and $154,000 as of December 31, 2011.

Completion and Well Servicing Services

The Company contracted with an affiliate for certain of its well completion services. Effective August 24, 2011, the affiliate was sold to a non-related third party. While still an affiliate of the Company, the Company was billed $12,511,000 and $7,709,000 during the years ended December 31, 2011 and 2010, respectively. Such amounts are capitalized in oil and natural gas properties in the accompanying combined consolidated balance sheet. At December 31, 2012 and December 31, 2011, the entity was no longer a related party.

Marketing Services

The Company entered into an agreement on March 1, 2009 with an entity under common management that purchased and received a significant portion of the Company's oil volumes. December 1, 2011, the Company ceased all sales of its production under this agreement and effective January 1, 2012 the agreement with the affiliate was canceled. The Company's revenues from the affiliate were $38,873,000 and $21,403,000 during the years ended December 31, 2011 and 2010, respectively, and such amounts are included in oil sales–related party in the accompanying combined consolidated statements of operations. As of December 31, 2011, the Company had an accounts receivable-related party balance with the affiliate of $4,347,000 and such amount is included in the accompanying combined consolidated balance sheets.

MidMar

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with MidMar Gas LLC ("MidMar"), an entity affiliated with Wexford that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, MidMar is obligated to purchase from the Company, and the Company is obligated to sell to MidMar, all of the gas conforming to certain quality specifications produced from certain of the Company's 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 obligated to pay the Company 87% of the net revenue received by MidMar for all components of the Company's dedicated gas, including the 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 Chevron's Headlee plant. MidMar paid the Company $2,958,000, $3,128,000 and $1,066,000 during the years ended December 31, 2012, 2011 and 2010, respectively. As of December 31, 2012 and 2011, MidMar owed the Company $6,000 and $462,000, respectively, for the Company's portion of the net proceeds from the sale of gas, gas products and residue gas.

Midland Lease

Effective May 15, 2011, the Company occupied corporate office space in Midland, Texas under a lease with a five-year term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $155,000 and $40,000, during the years ended December 31, 2012 and 2011, respectively. The current monthly rent under the lease will increase approximately 4% annually on June 1 of each year during the lease term.

Oklahoma City Lease

Effective January 1, 2012, the Company occupied corporate office space in Oklahoma City, Oklahoma under a lease with a 67 month term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $329,000 during the year ended December 31, 2012. The monthly rent under the lease increased 9% on August 1, 2012 with no further escalations for the remaining term of the lease.

Advisory Services Agreement & Professional Services from Wexford

The Company entered into an advisory services agreement (the "Advisory Services Agreement") with Wexford, dated as of October 11, 2012, under which Wexford provides the Company with general financial and strategic advisory services related to the business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. The Advisory Services Agreement has a term of two years commencing on October 18, 2012, 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. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Company terminates such agreement, it is obligated to pay all amounts due through the remaining term. In addition, the Company agreed to pay Wexford to-be-negotiated market-based fees approved by the Company's independent directors for such services as may be provided by Wexford at the Company's request in connection with future acquisitions and divestitures, financings or other transactions in which the Company may be involved. The services provided by Wexford under the Advisory Services Agreement do not extend to the Company's day-to-day business or operations. The Company has agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Advisory Services Agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct. The Company incurred total costs of $191,000 during the year ended December 31, 2012 under the Advisory Services Agreement. As of December 31, 2012 the Company owed Wexford $113,000 and this amount is included in accounts payable-related party in the accompanying combined consolidated balance sheets. The Company did not incur any costs for professional services from Wexford during the years ended December 31, 2011 and 2010.

10. INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. As discussed in Note 1, Diamondback Energy LLC merged with and into Diamondback on October 11, 2012 and accordingly Diamondback will file a consolidated return for the period October 11, 2012 through December 31, 2012. Prior to the Merger, the Predecessors were not subject to corporate income taxes.

The components of federal income tax provision for the year ended December 31, 2012 are as follows:

Deferred tax provision:		
Deferred recognized at date of Merger - change in tax status of Predecessors	$	54,142,000
Deferred as a result of operations from October 11, 2012 through December 31, 2012		761,000
Total provision for income taxes	$	54,903,000

A reconciliation of the statutory federal income tax amount to the recorded expense is as follows:

Income tax expense at the federal statutory rate (35%)	$	6,434,000
Deduction for pre-merger LLC earnings		(5,717,000)
Income tax expense at 35% for period from October 11, 2012 through December 31, 2012		717,000
Income tax expense relating to change in tax status		54,142,000
State income tax		42,000
Non-deductible expenses		2,000
Provision for income taxes	$	54,903,000

The components of the Company's deferred tax assets and liabilities as of December 31, 2012 are as follows:

Current:		
Deferred tax assets		
Derivative instruments	$	1,857,000
Total current deferred tax assets		1,857,000
Noncurrent:		
Deferred tax assets		
Net operating loss carryforwards (subject to 20 year expiration)		1,577,000
Stock based compensation		930,000
Total noncurrent deferred tax assets		2,507,000
Deferred tax liabilities		
Oil and natural gas properties and equipment		64,636,000
Other		566,000
Total noncurrent deferred tax liabilities		65,202,000
Net noncurrent deferred tax liabilities		62,695,000
Net deferred tax liabilities	$	60,838,000

At December 31, 2012, the Company has a net operating loss carryforward of $4,506,000 that will begin expiring in approximately 2033.

11. DERIVATIVES

All derivative financial instruments are recorded at fair value. The fair value of swaps is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the realized and unrealized changes in fair value in the combined consolidated statements of operations under the caption "Gain (loss) on derivative instruments."

The Company has used price swap derivatives to reduce price volatility associated with certain of its oil sales. In these swaps, the Company receives the fixed price per the contract and pays a floating market price to the counterparty based on New York Mercantile Exchange Light Sweet Crude Oil pricing. The fixed-price payment and the floating-price payment are offset, resulting in a net amount due to or from the counterparty. The counterparties to the Company's derivative contracts are BNP Paribas ("BNP") and Hess Corporation ("Hess"), who the Company believes are acceptable credit risks.

On October 4, 2011, in order to lock-in prices on the anticipated base level of production, while at the same time providing downside protection for the borrowing base under the revolving credit facility, the Company executed with BNP, West Texas Intermediate light sweet crude oil swaps on the NYMEX for calendar year 2012 and 2013 of one thousand barrels per day priced at $78.50 and $80.55, respectively.

Set forth below are the summarized amounts, terms and fair values of outstanding instruments held as of December 31, 2012 and December 31, 2011.

			December 31,	
			2012	2011
Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Fair Value Liability	Fair Value Liability
Crude Oil Swaps:				
January – November 2012	335,000	$78.50	$ —	$ 6,833,000
December 2012	31,000	$78.50	302,000	594,000
January – December 2013	365,000	$80.55	4,614,000	5,545,000

The Company enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, the Company receives a floating price for the hedged commodity and pays 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, the Company placed a swap contract with Hess covering 1,680,000 Bbls of crude oil for the period from January 2008 to December 2012 at various fixed prices. In April 2008, the Company 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, the Company entered into an additional series of counter-swaps to lock-in the value of the remaining swaps settling 324,000 Bbls of crude oil swaps.

Set forth below are the summarized amounts, terms and fair values of the locked-in swaps from the April 2008 settlements as of December 31, 2012 and December 31, 2011, respectively.

				December 31,	
				2012	2011
Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price(per Bbl)	Fair Value Liability	Fair Value Liability
Crude Oil Swaps:					
December 2011	22,500	$82.90	$98.50–$102.20	$ —	$ 379,000
January-November 2012	247,500	$85.07	$98.25–$101.80	—	3,554,000
December 2012	22,500	$85.07	$98.25–$101.80	323,000	323,000

Set forth below are the summarized amounts, terms and fair values of the locked-in swaps from the June 2009 settlements as of December 31, 2012 and December 31, 2011, respectively.

				December 31,	
				2012	2011
Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price(per Bbl)	Fair Value Asset	Fair Value Asset
Crude Oil Swaps:					
December 2011	7,500	$82.90	$78.42	$ —	$ 34,000
January-November 2012	82,500	$85.07	$80.52	—	375,000
December 2012	7,500	$85.07	$80.52	34,000	34,000

None of the Company's derivatives have been designated as hedges. As such, all changes in fair value are immediately recognized in earnings. The following summarizes the loss on derivative instruments included in the combined consolidated statements of operations:

	Year Ended December 31,		
	2012	2011	2010
Unrealized gain (loss) on open non-hedge derivative instruments	$ 8,057,000	$ (12,972,000)	$ —
Loss on settlement of non-hedge derivative instruments	(5,440,000)	(37,000)	(148,000)
Gain (loss) on derivative instruments	$ 2,617,000	$ (13,009,000)	$ (148,000)

The Company is required to provide margin deposits to Hess whenever its unrealized losses exceed predetermined credit limits. The Company had a margin deposit held by Hess of zero and $2,326,000 as of December 31, 2012 and December 31, 2011, respectively, which earns interest that is remitted to the Company. As the Company has a master netting agreement with Hess, the Company has offset this margin deposit against its derivative positions.

12. FAIR VALUE MEASUREMENTS

The Company measures and discloses fair value in accordance with ASC Topic 820, *Fair Value Measurements and Disclosures* ("ASC Topic 820"). Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs.

ASC Topic 820 describes a fair value hierarchy based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. The Company's assessment of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy. The Company uses appropriate valuation techniques based on available inputs to measure the fair values of its assets and liabilities.

Level 1 - Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2 - Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3 - Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2012 and December 31, 2011.

	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Cash Collateral(1)	Net Fair Value
Financial Liabilities					
			December 31, 2012		
Derivative instruments	$ —	$ 5,205,000	$ —	$ —	$ 5,205,000
			December 31, 2011		
Derivative instruments	$ —	$ 16,785,000	$ —	$ (2,326,000)	$ 14,459,000

(1) Represents the impact of netting cash collateral with a counterparty with which the right of offset exists.

Level 2 Fair Value Measurements

Derivative instruments-The fair values of the Company's crude oil swaps are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. These valuations are Level 2 inputs.

13. COMMITMENTS AND CONTINGENCIES

The Company 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.

Lease Commitments

The following is a schedule of minimum future lease payments with commitments that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2012.

Year Ending December 31,	Office and Equipment Leases
2013	$ 485,000
2014	491,000
2015	501,000
2016	412,000
2017	281,000
Thereafter	25,000
Total	$ 2,195,000

In March 2011, the Company began leasing field office space in Midland, Texas from an unrelated party. The lease term is 84 months with equal monthly installments that escalate 3% annually on March 1st of each year. In May 2011, the Company began leasing corporate office space in Midland, Texas from an entity controlled by an affiliate of Wexford. The lease term is 5 years with monthly rent under the lease set to increase approximately 4% annually on June 1st of each year. Effective January 1, 2012, the Company occupied corporate office space in Oklahoma City, Oklahoma under a lease with a 67 month term. The office space is owned by an entity controlled by an affiliate of Wexford. The monthly rent under the lease increased 9% on August 1, 2012 with no further escalations for the remaining term of the lease. The related party leases are also disclosed in Note 9—Related Party Transactions. The following table presents rent expense for the years ended December 31, 2012, 2011 and 2010.

	For the years ended December 31,		
	2012	2011	2010
Rent Expense	$ 547,000	$ 74,000	$ —

Fracturing and well stimulation agreement

The Company has a contractual obligation with a third-party service provider for fracturing and well stimulation services. The following is a schedule of minimum future expenditures for fracturing and well stimulation service services as of December 31, 2012.

Year Ending December 31,	Fracturing and Well Stimulation Service Agreements
2013	$ 14,400,000
2014	3,600,000
Total	$ 18,000,000

Drilling contracts

The Company has committed to short term drilling contracts with Bison Drilling and Field Services LLC under a master service agreement. This master drilling agreement is terminable by either party on 30 day prior written notice, although neither party will be relieved of its respective obligations arising from a drilling contract being performed prior to the termination of the master drilling agreement. Refer to the related party footnote for additional disclosure regarding Bison.

Defined contribution plan

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at their date of hire. The plan allows eligible employees to contribute up to 100% of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to 6% of an employee’s compensation and may make additional discretionary contributions for eligible employees. Employer contributions vest in equal annual installments over a 4 year period. The Company paid $86,000 in contributions to the plan for the year ended December 31, 2012. Prior to 2012, the previous plan was sponsored under the shared service agreements discussed in Note 9—Related Party Transactions and the Company did not directly contribute to the previous plan.

14. SUBSEQUENT EVENTS

On February 1, 2013, the Company entered into a new commodity contract with Wells Fargo. The derivative is a fixed price oil swap that will settle against the average of the prompt month Brent Crude futures price derived from the International Petroleum Exchange. The following table presents the terms of the contract:

	Aggregate volumes (Bbls)	Swap Price	Contract Period
Fixed-Price Swap	365,000	$ 109.70	May 2013 - April 2014

On January 22, 2013, the Company merged Windsor UT into Windsor Permian and the surviving entity was subsequently renamed Diamondback O&G LLC. This merger consolidates the oil and natural gas interests into one company, Diamondback O&G LLC, which is a wholly-owned subsidiary of the Company.

On January 28, 2013, the Company entered into a master drilling agreement effective as of January 1, 2013 with Bison Drilling and Field Services LLC ("Bison"). This agreement supersedes the previous master drilling agreement that was effective as of January 1, 2012. Bison committed to accept orders from the Company for the use of at least two of its rigs, that the Company may require from time-to-time, in the Company's sole discretion, that one of the rigs be used for horizontal wells. The master drilling agreement provides fixed day rate agreements for vertical and horizontal wells, is 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 the termination of the master drilling agreement.

On January 28, 2013, the Company entered into a master field services agreement effective as of January 1, 2013 with Bison. Under the master field services agreement, the Company may order certain field services and purchase or lease goods, equipment or facilities from Bison provided, however, that the Company is not obligated to place, and Bison is not obligated to accept, orders for such services or goods. The master field services agreement is terminable by either party on 30 days' prior written notice, although neither party will be relieved of its respective obligations arising from a field services contract being performed prior to the termination of the master field services agreement.

15. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (Unaudited)

The Company’s oil and natural gas reserves are attributable solely to properties within the United States.

Capitalized oil and natural gas costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are as follows:

	December 31,	
	2012	2011
Oil and Natural Gas Properties:		
Proved properties	$ 576,497,000	$ 335,303,000
Unproved properties	121,245,000	4,528,000
Total Oil and Natural Gas Properties	697,742,000	339,831,000
Less Accumulated depreciation, depletion, amortization and impairment	(145,102,000)	(119,366,000)
Net oil and natural gas properties capitalized	$ 552,640,000	$ 220,465,000

Costs incurred in oil and natural gas activities

Costs incurred in oil and natural gas property acquisition, exploration and development activities are as follows:

	Year Ended December 31,		
	2012	2011	2010
Acquisition costs			
Proved properties	$ 115,760,000	$ —	$ —
Unproved properties	117,395,000	3,704,000	9,930,000
Development costs	106,261,000	75,374,000	48,817,000
Exploration costs	17,547,000	11,226,000	3,920,000
Capitalized asset retirement costs	948,000	297,000	222,000
Total	$ 357,911,000	$ 90,601,000	$ 62,889,000

Results of Operations from Oil and Natural Gas Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and natural gas. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil, natural gas and natural gas liquids operations.

	Year Ended December 31,		
	2012	**2011**	**2010**
Oil, natural gas and natural gas liquid sales	$ 74,962,000	$ 47,875,000	$ 26,442,000
Lease operating expenses	(16,793,000)	(10,597,000)	(4,589,000)
Production taxes	(3,691,000)	(2,366,000)	(1,347,000)
Gathering and transportation	(424,000)	(202,000)	(106,000)
Depreciation, depletion, and amortization	(25,772,000)	(15,377,000)	(7,373,000)
Results of operations from oil, natural gas and natural gas liquids before income taxes	$ 28,282,000	$ 19,333,000	$ 13,027,000
Pro forma information			
Pro forma income tax[(1)]	10,083,000		
Pro forma results of operations	$ 18,199,000		

(1) Diamondback Energy, Inc. was formed as a holding company on December 30, 2011, and did not conduct any material business operations prior to the Merger. Diamondback Energy, Inc. is a C-Corp under the Internal Revenue Code and is subject to income taxes. The Company computed a pro forma income tax provision as if the Company and the Predecessors were subject to income taxes since December 31, 2011. 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.

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates as of December 31, 2012 and 2011 were prepared by Ryder Scott Company, L.P., and as of December 31, 2010 were prepared by Pinnacle Energy Services, LLC, both independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The changes in estimated proved reserves are as follows:

	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Developed and Undeveloped Reserves:			
As of January 1, 2010	29,230,940	7,522,225	27,481,820
Extensions and discoveries	2,402,204	1,463,206	14,043,737
Revisions of previous estimates	(11,722,263)	(3,072,486)	(18,506,630)
Purchase of reserves in place	—	—	—
Production	(280,721)	(79,978)	(323,847)
Sales of reserves in place	—	—	—
As of December 31, 2010	19,630,160	5,832,967	22,695,080
Extensions and discoveries	1,799,175	466,538	1,884,192
Revisions of previous estimates	(2,879,429)	(1,163,130)	(3,614,167)
Purchase of reserves in place	—	—	—
Production	(449,433)	(86,815)	(413,640)
Sales of reserves in place	—	—	—
As of December 31, 2011	18,100,473	5,049,560	20,551,465
Extensions and discoveries	3,106,433	869,741	3,759,684
Revisions of previous estimates	(1,464,243)	(5,811)	383,335
Purchase of reserves in place	7,210,482	2,521,053	10,709,180
Production	(756,286)	(183,114)	(833,516)
Sales of reserves in place	—	—	—
As of December 31, 2012	26,196,859	8,251,429	34,570,148
Proved Developed Reserves:			
January 1, 2010	1,954,060	591,532	2,453,750
December 31, 2010	3,371,460	1,126,431	4,336,720
December 31, 2011	3,949,099	1,263,711	5,285,945
December 31, 2012	7,189,367	2,999,440	12,864,941
Proved Undeveloped Reserves:			
January 1, 2010	27,276,880	6,930,693	25,028,070
December 31, 2010	16,258,700	4,706,536	18,358,360
December 31, 2011	14,151,375	3,785,850	15,265,520
December 31, 2012	19,007,492	5,251,989	21,705,207

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

The Company experienced downward reserve revisions in estimated proved oil and natural gas liquid reserves in 2012. These downward revisions were primarily a result from lower product pricing in 2012 as compared to 2011 causing wells to reach their economic limit sooner. The upward revision in natural gas reserves is the result of higher producing natural gas to oil ratios than previously projected, which more than offset the reduction resulting from lower natural gas prices.

The Company experienced downward reserve revisions in estimated proved reserves in 2011. These downward revisions were primarily the result of negative revisions in proved undeveloped wells due to offset well performance; exclusion of proved undeveloped locations that were not scheduled to be drilled within the next five years; and the movement of reserves previously categorized as proved undeveloped to probable reserves due to changes in booking methodology used by our independent petroleum engineers as well as performance of wells in one prospect area.

The Company experienced downward reserve revisions in 2010, due to undeveloped locations being scheduled for development beyond five years and thus being excluded from proved reserves.

Standardized Measure of Discounted Future Net Cash Flows

The following information has been prepared in accordance with the provisions of the FASB Codification, Topic 932– “Extractive Activities—Oil and Gas.” The standardized measure of discounted future net cash flows are based on the unweighted average, first-day-of-the-month price. The projections should not be viewed as realistic estimates of future cash flows, nor should the “standardized measure” be interpreted as representing current value to the Company. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

The following table sets forth the standardized measure of discounted future net cash flows attributable to the Company’s proved oil and natural gas reserves as of December 31, 2012, 2011 and 2010.

	December 31,		
	2012	2011	2010
Future cash inflows	$ 2,769,485,000	$ 2,049,520,000	$ 1,856,294,000
Future development costs	(541,445,000)	(410,350,000)	(398,305,000)
Future production costs	(773,611,000)	(497,808,000)	(384,916,000)
Future production taxes	(140,758,000)	(104,856,000)	(126,090,000)
Future income tax expenses	(334,903,000)	—	—
Future net cash flows	978,768,000	1,036,506,000	946,983,000
10% discount to reflect timing of cash flows	(611,548,000)	(671,894,000)	(607,982,000)
Standardized measure of discounted future net cash flows	$ 367,220,000	$ 364,612,000	$ 339,001,000

In the table below the average first-day-of–the-month price for oil, natural gas and natural gas liquids is presented, all utilized in the computation of future cash inflows.

Diamondback Energy, Inc. and Subsidiaries
Notes to Combined Consolidated Financial Statements-(Continued)

	December 31,		
	2012	2011	2010
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (per Bbl)	$ 88.13	$ 93.09	$ 77.61
Natural gas (per Mcf)	$ 2.86	$ 3.91	$ 4.14
Natural gas liquids (per Bbl)	$ 43.88	$ 56.33	$ 40.74

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves are as follows:

	Year Ended December 31,		
	2012	2011	2010
Standardized measure of discounted future net cash flows at the beginning of the period	$ 364,612,000	$ 339,001,000	$ 392,919,000
Sales of oil and natural gas, net of production costs	(54,208,000)	(34,711,000)	(20,401,000)
Purchase of minerals in place	107,897,000	—	—
Extensions and discoveries, net of future development costs	79,293,000	73,571,000	59,414,000
Previously estimated development costs incurred during the period	88,849,000	87,530,000	52,932,000
Net changes in prices and production costs	(76,515,000)	82,364,000	178,198,000
Changes in estimated future development costs	8,309,000	(82,855,000)	(23,992,000)
Revisions of previous quantity estimates	(22,882,000)	(98,533,000)	(292,306,000)
Sales of reserves in place, net of future development costs	—	—	—
Accretion of discount	36,461,000	33,900,000	39,292,000
Net change in income taxes	(125,542,000)	—	—
Net changes in timing of production and other	(39,054,000)	(35,655,000)	(47,055,000)
Standardized measure of discounted future net cash flows at the end of the period	$ 367,220,000	$ 364,612,000	$ 339,001,000

16. QUARTERLY FINANCIAL DATA (Unaudited)

The Company's unaudited quarterly financial data for 2012 and 2011 is summarized below.

	2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 16,351,000	$ 16,030,000	$ 16,814,000	$ 25,767,000
Income from operations	6,737,000	4,307,000	4,086,000	2,177,000
Income tax expense	—	—	—	54,903,000
Net income (loss)	$ 1,477,000	$ 13,624,000	$ 452,000	$ (52,074,000)
Pro forma information				
Income before income taxes	$ 1,477,000	$ 13,624,000	$ 452,000	$ 2,829,000
Pro forma provision for income taxes	526,000	4,857,000	161,000	1,009,000
Pro forma net income	$ 951,000	$ 8,767,000	$ 291,000	$ 1,820,000
Pro forma earnings per share:				
Basic	$ 0.06	$ 0.60	$ 0.02	$ 0.05
Diluted	$ 0.06	$ 0.60	$ 0.02	$ 0.05

	2011			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 12,087,000	$ 11,572,000	$ 11,216,000	$ 14,491,000
Income from operations	3,328,000	4,067,000	2,928,000	4,824,000
Net income (loss)	$ 2,824,000	$ 3,453,000	$ 2,205,000	$ (8,868,000)

Pro Forma Income Taxes

Diamondback Energy, Inc. was formed as a holding company on December 30, 2011, and did not conduct any material business operations prior to the Merger. Diamondback Energy, Inc. is a C-Corp under the Internal Revenue Code and is subject to income taxes. The Company computed a pro forma income tax provision as if the Company and the Predecessors were subject to income taxes since December 31, 2011. 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.

Pro Forma Earnings per Share

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 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.

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.2	Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.1	Specimen certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
4.2	Registration Rights Agreement, dated as of October 11, 2012, by and between the Company and DB Energy Holdings LLC (incorporated by reference to Exhibit 4.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.3	Investor Rights Agreement, dated as of October 11, 2012, by and between the Company and Gulfport Energy Corporation (incorporated by reference to Exhibit 4.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
10.1+	Equity Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.13 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
10.3+	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.14 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
10.4+	Form of Director and Officer Indemnification Agreement (incorporated by reference to Exhibit 10.15 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
10.5	Advisory Services Agreement, dated as of October 11, 2012, by and between Diamondback Energy, Inc. and Wexford Capital LP (incorporated by reference to Exhibit 10.4 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
10.6	Merger Agreement, dated as of October 11, 2012, by and between the Company and Diamondback Energy LLC (incorporated by reference to Exhibit 10.5 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
10.7+	Amended and Restated Employment Agreement, dated as of August 20, 2012, by and between Travis Stice and Windsor Permian LLC (incorporated by reference to Exhibit 10.29 to Amendment No. 5 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on October 2, 2012).
10.8+	First Amendment effective as of January 1, 2013 to the Amended and Restated Employment Agreement dated as of August 20, 2012 by and between Travis Stice and Windsor Permian LLC, as subsequently assigned to Diamondback E&P LLC (incorporated by reference to Exhibit 10.3 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 1, 2013).
10.9+	Amended and Restated Employment Agreement, dated as of January 1, 2012, by and between Teresa Dick and Windsor Permian LLC (incorporated by reference to Exhibit 10.30 to Amendment No. 3 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on July 5, 2012).
10.10+	First Amendment effective as of January 1, 2013 to the Amended and Restated Employment Agreement dated as of August 20, 2012 by and between Teresa Dick and Windsor Permian LLC, as subsequently assigned to Diamondback E&P LLC (incorporated by reference to Exhibit 10.4 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 1, 2013).
10.11+	Amended and Restated Employment Agreement, dated as of January 1, 2012, by and between Jeff White and Windsor Permian LLC (incorporated by reference to Exhibit 10.31 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).

Exhibit Number	Description
10.12+	First Amendment effective as of January 1, 2013 to the Amended and Restated Employment Agreement dated as of August 20, 2012 by and between Jeff White and Windsor Permian LLC, as subsequently assigned to Diamondback E&P LLC (incorporated by reference to Exhibit 10.5 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 1, 2013).
10.13	Amended and Restated Credit Agreement, dated July 24, 2012, by and among Diamondback Energy LLC, as borrower, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.33 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
10.14	First Amendment to Credit Agreement, dated July 31, 2012, by and among Diamondback Energy LLC, as borrower, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.34 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
10.15	Lease Agreement, dated as of April 19, 2011, by and between Fasken Midland, LLC and Windsor Permian LLC (incorporated by reference to Exhibit 10.7 to Amendment No. 2 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on June 11, 2012).
10.16	Lease Amendment No. 1 to Lease Agreement, dated as of June 6, 2011, by and between Fasken Midland, LLC and Windsor Permian LLC (incorporated by reference to Exhibit 10.8 to Amendment No. 1 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on May 8, 2012).
10.17	Lease Amendment No. 2 to Lease Agreement, dated as of August 5, 2011, by and between Fasken Midland, LLC and Windsor Permian LLC (incorporated by reference to Exhibit 10.9 to Amendment No. 1 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on May 8, 2012).
10.18	Lease Amendment No. 3 to Lease Agreement, dated as of September 28, 2011, by and between Fasken Midland, LLC and Windsor Permian LLC (incorporated by reference to Exhibit 10.10 to Amendment No. 1 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on May 8, 2012).
10.19	Lease Amendment No. 4 to Lease Agreement, dated February 6, 2012, by and between Fasken Midland, LLC and Windsor Permian LLC (incorporated by reference to Exhibit 10.11 to Amendment No. 1 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on May 8, 2012).
10.20	Lease Amendment No. 5 to Lease Agreement, dated as of July 25, 2012, by and between Fasken Midland, LLC and Diamondback E&P LLC (incorporated by reference to Exhibit 10.36 to Amendment No. 5 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on October 2, 2012).
10.21	Contribution Agreement, dated May 7, 2012, by and between the Company and Gulfport Energy Corporation (incorporated by reference to Exhibit 10.18 to Amendment No. 1 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on May 8, 2012).
10.22	Master Drilling Agreement, dated January 1, 2012, by and between Windsor Permian LLC and Bison Drilling and Field Services LLC (incorporated by reference to Exhibit 10.19 to Amendment No. 1 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on May 8, 2012).
10.23	Gas Purchase Agreement, dated May 1, 2009, by and between Windsor Permian LLC and Feagan Gathering Company (incorporated by reference to Exhibit 10.20 to Amendment No. 1 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on May 8, 2012).
10.24	Amendment to Gas Purchase Agreement, dated July 1, 2011, by and between Windsor Permian LLC and MidMar Gas LLC (incorporated by reference to Exhibit 10.21 to Amendment No. 1 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on May 8, 2012).
10.25	Amendment to Gas Purchase Agreement, dated January 11, 2012, by and between Windsor Permian LLC and MidMar Gas LLC (incorporated by reference to Exhibit 10.22 to Amendment No. 1 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on May 8, 2012).

Exhibit Number	Description
10.26	Shared Services Agreement, dated January 1, 2012 by and between Windsor Permian LLC and Everest Operations Management LLC (incorporated by reference to Exhibit 10.23 to Amendment No. 2 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on June 11, 2012).
10.27	Subordinated note made by Windsor Permian LLC in favor of Lambda Investors LLC, dated May 14, 2012 (incorporated by reference to Exhibit 10.23 to Amendment No. 2 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on June 11, 2012).
10.28	First Amendment to Subordinated Note made by Windsor Permian LLC in favor of Lambda Investors LLC, dated September 28, 2012 (incorporated by reference to Exhibit 10.35 to Amendment No. 5 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on October 2, 2012).
10.29	Crude Oil Purchase Agreement, dated May 24, 2012, by and between Windsor Permian LLC and Shell Trading (US) Company (incorporated by reference to Exhibit 10.26 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
10.30	Shared Services Agreement, dated as of March 1, 2008, by and between Windsor Energy Resources LLC and Windsor Permian LLC (incorporated by reference to Exhibit 10.6 to Amendment No. 1 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on May 8, 2012).
10.31	Office Lease Agreement, dated June 8, 2012, by and between Windsor Permian LLC and Caliber Investment Group LLC (incorporated by reference to Exhibit 10.27 to Amendment No. 3 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on July 5, 2012).
10.32	Assignment and Assumption of Office Lease Agreement, effective June 1, 2012, by and between Windsor Permian LLC and Diamondback E&P LLC (incorporated by reference to Exhibit 10.28 to Amendment No. 3 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on July 5, 2012).
10.33	Master Drilling Agreement, effective as of January 1, 2013, by and between Diamondback E&P LLC and Bison Drilling and Field Services LLC (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 1, 2013).
10.34	Master Field Services Agreement, effective as of January 1, 2013, by and between Diamondback E&P LLC and Bison Drilling and Field Services LLC (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on February 1, 2013).
10.35*	First Amendment to Master Field Services Agreement, dated as of February 21, 2013, by and between Diamondback E&P LLC and Bison Drilling and Field Services LLC.
21.1*	List of Significant Subsidiaries of the Company.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1++	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2++	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Ryder Scott Company, L.P.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Labels Linkbase Document.

Exhibit Number	Description
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

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* Filed herewith.

** Furnished herewith. Pursuant to Rule 406T of Regulation S-T, these interactive data files are being furnished herewith and are not deemed filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are not deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under these sections.

\+ Management contract, compensatory plan or arrangement.

++ The certifications attached as Exhibit 32.1 and Exhibit 32.2 accompany this Annual Report on Form 10-K pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not be deemed “filed” by the Registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

Exhibit 10.35

FIRST AMENDMENT TO
MASTER FIELD SERVICES AGREEMENT

THIS FIRST AMENDMENT TO MASTER FIELD SERVICES AGREEMENT (this "Amendment") is made and entered into as of February 21, 2013, by and between DIAMONDBACK E&P LLC ("Operator") and BISON DRILLING AND FIELD SERVICES LLC ("Contractor").

RECITALS:

A. Operator and Contractor are parties to that certain Master Field Services Agreement dated January 1, 2013 (the "Agreement").

B. The parties desire to amend the Agreement in the manner hereinafter set forth.

NOW, THEREFORE, in consideration of the premises, covenants and conditions herein, and other valuable consideration, the receipt and sufficiency of which is hereby acknowledged, Operator and Contractor hereby agree as follows:

1. Compensation. Exhibit "C" (Rate Schedule - Trailers, Forklifts and Well Spudders Only) of the Agreement is hereby deleted in its entirety and replaced with Exhibit "C" attached hereto.

2. Entire Agreement. All prior understandings and agreements between the parties with respect to the subject matter of this Amendment are merged within this Amendment, which alone fully and completely sets forth the understanding of the parties with respect thereto. This Amendment may not be changed or modified nor may any of its provisions be waived orally or in any manner other than by a writing signed by the party against whom enforcement of the change, modification or waiver is sought.

3. Agreement. Except as herein provided, the Agreement and all off its terms, covenants and conditions remain in full force and effect.

4. Execution Counterparts. This Amendment may be executed in any number of counterparts, and each such counterpart hereof shall be deemed to be an original instrument. All such counterparts together shall constitute for all purposes one agreement.

(signature page following)

IN WITNESS WHEREOF, Operator and Contractor have executed this Amendment as of the day and year first written above.

OPERATOR:

DIAMONDBACK E&P LLC

By: /s/ Travis D. Stice

Name: Travis D. Stice

Title: Chief Executive Officer

CONTRACTOR:

BISON DRILLING AND FIELD SERVICES LLC

By: /s/ Kaes Vanthof

Name: Kaes Vanthof

Title: Chief Executive Officer

<u>EXHIBIT "C"</u>

Rate Schedule
(Trailers, Forklifts and Well Spudders Only)

Trailers:

- $125 / day

Forklifts:

- $100 / day

Well Spudders

- $75 / foot
- $3,000 / Move in Midland County
- $4,000 / Move in Upton County
- Note: Contractor does not currently provide pre-set pricing in any other counties, but there will likely be an agreed-upon move fee for such other counties.
- $7,500 / Rathole and Mousehole

Exhibit 21.1

Significant Subsidiaries of Diamondback Energy, Inc.

Diamondback E&P LLC
Diamondback O&G LLC

Exhibit 31.1

CERTIFICATION

I, Travis D. Stice, certify that:

1. I have reviewed this Annual Report on Form 10-K of Diamondback Energy, Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (c) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: March 1, 2013

/s/ Travis D. Stice

Travis D. Stice
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Teresa L. Dick, certify that:

1. I have reviewed this Annual Report on Form 10-K of Diamondback Energy, Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2013

/s/ Teresa L. Dick

Teresa L. Dick
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PERIOD REPORT

I, Travis D. Stice, Chief Executive Officer of Diamondback Energy, Inc. (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2012 (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2013	/s/ Travis D. Stice
	Travis D. Stice
	Chief Executive Officer

The foregoing certifications are not deemed filed with the Securities and Exchange Commission for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and are not to be incorporated by reference into any filing of Diamondback Energy, Inc. under the Securities Act of 1933, as amended, or the Exchange Act, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 32.2

CERTIFICATION OF PERIOD REPORT

I, Teresa L. Dick, Chief Financial Officer of Diamondback Energy, Inc. (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2012 (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2013	/s/ Teresa L. Dick
	Teresa L. Dick
	Chief Financial Officer

The foregoing certifications are not deemed filed with the Securities and Exchange Commission for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and are not to be incorporated by reference into any filing of Diamondback Energy, Inc. under the Securities Act of 1933, as amended, or the Exchange Act, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

DIAMONDBACK ENERGY, INC.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2012

/s/ Don P. Griffin, P.E.
Don P. Griffin, P.E. TBPE
License No. 64150
Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPE Firm License No. F-1580

January 16, 2013

Diamondback Energy, Inc.
500 West Texas, Suite 1210
Midland, Texas 79701

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of Diamondback Energy, Inc. (Diamond) as of December 31, 2012. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 11, 2013 and presented herein, was prepared for public disclosure in Diamond's filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Diamond as of December 31, 2012.

The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
Diamondback Energy, Inc.
As of December 31, 2012

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate - MBbl	6,839	350	19,008	26,197
Plant Products - MBbl	2,917	83	5,251	8,251
Gas - MMCF	12,526	339	21,705	34,570
MBOE	11,843	490	27,877	40,210
Income Data ($M)				
Future Gross Revenue	$726,722	$33,857	$1,868,147	$2,628,726
Deductions	262,269	10,969	1,041,817	1,315,055
Future Net Income (FNI)	$464,453	$22,888	$826,330	$1,313,671
Discounted FNI @ 10%	$255,062	$13,078	$224,622	$492,762

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

The estimated reserves and future net income amounts presented in this report, as of December 31, 2012 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the un-weighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report.

Liquid hydrocarbons are expressed in thousands of standard 42 gallon barrels (MBbl). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net remaining reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousands barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package AriesTM System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used solely at the request of Diamond. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 96.4 percent and gas reserves account for the remaining 3.6 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income As of December 31, 2012 ($M)
Discount Rate Percent	Total Proved
5	$532,693
15	$347,150
20	$256,603
25	$195,986

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various reserve status categories are defined under the attachment entitled "Petroleum Reserves Definitions" in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes included herein do not attribute gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Diamond's request, this report addresses the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." 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."

Reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Diamond's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which Diamond owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

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 set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). 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. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, analogy, or a combination of both methods. Approximately 85 percent of the proved producing reserves attributable to producing wells were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production and pressure data available through early December 2012 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Diamond and were considered sufficient for the purpose thereof. The remaining 15 percent of the proved 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 included herein were estimated by the analogy method**.**

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Diamond has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Diamond with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Diamond. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Diamond. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month un-weighted arithmetic average as previously described.

As noted above, Diamond furnished us with the average prices in effect on December 31, 2012. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the- month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Diamond and were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Diamond to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserve category for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Avg Benchmark Prices	Avg Proved Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$94.71/Bbl	$88.13/Bbl
	NGLs	Mt. Belvieu	$43.24/Bbl	$43.88/Bbl
	Gas	Henry Hub	$2.76/MMBTU	$2.86/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report are based on the operating expense reports of Diamond and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Diamond. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Diamond and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. Diamond’s estimates of zero abandonment costs after salvage value for onshore properties were used in this report. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Diamond’s estimate.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Diamond’s plans to develop these reserves as of December 31, 2012. The implementation of Diamond’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Diamond’s management. As the result of our inquiries during the course of preparing this report, Diamond has informed us that the development activities included herein have been subjected to and received the internal approvals required by Diamond’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to

Diamond. Additionally, Diamond has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

Current costs used by Diamond were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee- owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Diamond. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Diamond.

We have provided Diamond with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Diamond and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very Truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Don P. Griffin, P.E.
Don P. Griffin, P.E.
TBPE License No. 64150
Senior Vice President

DPG (FPR)/pl

[SEAL]

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Don P. Griffin was the primary technical person responsible for overseeing the estimate of the reserves, future production and income presented herein.

Mr. Griffin, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 1981, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Griffin served in a number of engineering positions with Amoco Production Company. For more information regarding Mr. Griffin's geographic and job specific experience, please refer to the Ryder Scott Company website at http://www.ryderscott.com/Experience/Employees.php.

Mr. Griffin graduated with honors from Texas Tech University with a Bachelor of Science degree in Electrical Engineering in 1975 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Griffin fulfills. Mr. Griffin attended an additional 15 hours of training during 2012 covering such topics as reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 30 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Griffin has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by: SOCIETY OF
PETROLEUM ENGINEERS (SPE) WORLD
PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals which are open at the time of the estimate, but which have not started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.