Diamondback Energy, Inc.
Form S-1/A
May 08, 2012
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As filed with the Securities and Exchange Commission on May 7, 2012

Registration No. 333-179502

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

AMENDMENT NO. 1

to

FORM S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Diamondback Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**45-4502447**
(State or other jurisdiction of		**(I.R.S. Employer**

incorporation or organization)	**(Primary Standard Industrial Classification Code Number)**	**Identification Number)**

500 West Texas

Suite 1225

Midland, Texas 79701

(432) 221-7400

(Address, including zip code and telephone number, including area code, of registrant s principal executive offices)

Teresa Dick

Chief Financial Officer

Diamondback Energy, Inc.

14301 Caliber Drive

Suite 300

Oklahoma City, Oklahoma 73134

(405) 463-6900

(Name, address, including zip code and telephone number, including area code, of agent for service)

Copies to:

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Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement is declared effective.

If any securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, as amended (the Securities Act), check the following box. ¨

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

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

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	x (Do not check if a smaller reporting company)	Smaller reporting company	¨

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act or until this Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. We and the selling stockholders may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and we and the selling stockholders are not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED MAY 7, 2012.

PROSPECTUS

Shares

Diamondback Energy, Inc.

Common Stock

We are selling shares of common stock and the selling stockholders are selling shares of common stock. We will not receive any of the proceeds from the shares of common stock sold by the selling stockholders.

Prior to this offering, there has been no public market for our common stock. The initial public offering price of the common stock is expected to be between $ and $ per share. We have applied to list our common stock on The NASDAQ Global Market under the symbol FANG.

We and the selling stockholders granted the underwriters an option to purchase up to an aggregate of additional shares of our common stock to cover the underwriters option to purchase additional shares.

We are an emerging growth company under applicable Securities and Exchange Commission rules and will be subject to reduced public company reporting requirements. Investing in our common stock involves risks. **See Risk Factors beginning on page 14.**

	Price to Public	Underwriting Discounts and Commissions	Proceeds to Diamondback	Proceeds to Selling Stockholders
Per Share	$	$	$	$
Total	$	$	$	$

Delivery of the shares of common stock will be made on or about , 2012.

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

Credit Suisse

The date of this prospectus is , 2012.

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ABOUT THIS PROSPECTUS

You should rely only on the information contained in this prospectus. We have not, and the selling stockholders and the underwriters have not, authorized any other person to provide you with information different from that contained in this prospectus. If anyone provides you with different or inconsistent information, you should not rely on it. We, the selling stockholders and the underwriters are only offering to sell, and only seeking offers to buy, our common stock in jurisdictions where offers and sales are permitted.

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

Dealer Prospectus Delivery Obligation

Until (25 days after the commencement of the offering), all dealers that effect transactions in these securities, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealer s obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.

Industry and Market Data

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

Unless the context otherwise requires, the information in this prospectus (other than in the historical financial statements) assumes that the underwriters will not exercise their option to purchase additional shares.

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PROSPECTUS SUMMARY

This summary contains basic information about us and the offering. Because it is a summary, it does not contain all the information that you should consider before investing in our common stock. Except as expressly noted otherwise, the historical assets, operations and results described in this prospectus are those of Windsor Permian LLC, or Windsor Permian, an entity controlled by Wexford Capital LP, or Wexford. Prior to the closing of this offering, Wexford will cause all of the outstanding equity interests in Windsor Permian to be contributed to us in exchange for shares of our common stock and Windsor Permian will become our wholly-owned subsidiary. On May 7, 2012, we entered into a contribution agreement with Gulfport Energy Corporation, or Gulfport, in which Gulfport, agreed to contribute to us, subject to certain conditions, all of its oil and natural gas interests in the Permian Basin in exchange for shares of our common stock and a promissory note. In addition, Wexford has agreed to cause all of the outstanding equity interests in Windsor UT LLC, or Windsor UT, to be contributed to Windsor Permian prior to the time Windsor Permian is contributed to us. Windsor UT owns oil and natural gas interests in the Permian Basin. In this prospectus, we refer to the Gulfport contribution and the Windsor UT contribution together as the Contributions. See Summary The Contributions beginning on page 6 of this prospectus for more information regarding the Contributions. Except as expressly noted otherwise, references to our operations and assets as of March 31, 2012 and thereafter give effect to the Contributions. You should read and carefully consider this entire prospectus before making an investment decision, especially the information presented under the heading Risk Factors and our financial statements and the accompanying notes included elsewhere in this prospectus, as well as the other documents to which we refer you. We have provided definitions for some of the oil and natural gas industry terms used in this prospectus in the Glossary of Oil and Natural Gas Terms.

DIAMONDBACK ENERGY, INC.

Overview

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

We began operations in December 2007 with our acquisition of 4,174 net acres with production at the time of acquisition of approximately 800 net barrels of oil equivalent, or BOE, per day from 33 gross (16.5 net) wells in the Permian Basin. Subsequently, we acquired approximately 25,851 additional net acres, which brought our total net acreage position in the Permian Basin to 30,025 net acres at March 31, 2012 and, after giving effect to the Contributions, we had 49,703 net acres. We are the operator of approximately 99% of this acreage. As of March 31, 2012, after giving effect to the Contributions, we had drilled 147 gross (136 net) wells, and participated in an additional 11 gross (five net) non-operated wells, in the Permian Basin. Of these 158 gross wells, 149 were completed as producing wells and nine are in various stages of completion. In the aggregate, as of March 31, 2012, we held interests in 182 gross (166 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.

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As of December 31, 2011, our estimated proved oil and natural gas reserves, pro forma for the Contributions, were 39,460 MBOE based on reserve reports prepared by Ryder Scott Company L.P., or Ryder Scott, our independent reserve engineers. Of these reserves, approximately 21.7% are classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate are from 329 gross well locations on 40-acre spacing. As of December 31, 2011, these proved reserves were approximately 67% oil, 20% natural gas liquids and 13% natural gas.

We have 977 identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data and we have an additional 1,162 identified potential vertical drilling locations based on 20-acre downspacing. These identified potential drilling locations do not include any potential horizontal drilling locations. 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, as estimated by Ryder Scott, range from 89 MBOE to 147 MBOE per well, with an average EUR per well of 127 MBOE. Our 2012 drilling plan currently contemplates drilling 72 gross (65 net) vertical wells and nine gross (eight net) horizontal wells in the Wolfberry play. We are currently using four drilling rigs and intend to add two additional rigs later in 2012.

We believe the experience gained from our historical drilling programs and the information obtained from the results of extensive industry drilling activity in the Permian Basin have helped us reduce the risk and uncertainity associated with drilling vertical wells on our Permian Basin acreage. We intend to supplement our vertical development drilling activity with horizontal wells targeting various intervals in the Wolfberry play. Our horizontal drilling program is intended to further capture the upside potential that may exist on our properties and increase our well performance and recoveries as compared to drilling vertical wells alone.

During 2011, we assembled a new executive team and, beginning with the fourth quarter of 2011, this team assumed management control of our operations and development activities in the Permian Basin. With an average of approximately 26 years of industry experience per person, this team has extensive experience in the Permian Basin as well as other resource plays in North America, including significant experience in drilling and completing horizontal wells. Under the direction of our new executive team, the average drilling time required to reach total depth, or TD, was shortened by 25% to 15 days during the fourth quarter of 2011 from 20 days during the second quarter of 2011, reducing average drilling costs (excluding completion costs) by 8.3% from $1.2 million to $1.1 million period-to-period, while also decreasing the time from spud to spud to 23 days from 25 days. Also, during the quarter ended March 31, 2012 our average daily production, pro forma for the Contributions, was 3,280 BOE/d, an increase of 11%, or 333 BOE/d, from 2,947 BOE/d for the quarter ended December 31, 2011. This increase was due primarily to improved strategies and procedures introduced by our new executive team relating to wellbore configuration, completion, execution, fluid recovery and well pumping practices that significantly reduced the level of required well remediation and the associated loss of production. We anticipate further increases in efficiencies as our new executive team executes on our development strategies across our acreage base.

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The following table provides a summary of selected operating information of our properties, pro forma for the Contributions. The information is as of March 31, 2012 except as otherwise noted.

Basin	Net Acreage	Average Working Interest	Identified Potential Drilling Locations[(1)] Gross	Net	2012 Budget Gross Wells[(2)]	Net Wells[(2)]	Capex (In millions)	Estimated Net Proved Reserves at December 31, 2011 MBOE	% Developed	Average Daily Production (BOE/d)[(3)]
Permian	49,703	86.2%	977	926	90	75	$ 180.0	39,460	24	3,378

(1) Reflects identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data. We have an additional 1,162 potential vertical drilling locations based on 20-acre downspacing. These identified potential drilling locations do not include any potential horizontal drilling locations. The drilling locations on which we actually drill wells will ultimately depend on the availability of capital, regulatory approvals, oil and natural gas prices, costs, actual drilling results and other factors.

(2) Includes 81 gross (72 net) wells for which we are the operator and nine gross (three net) non-operated wells.

(3) During February 2012.

Our current exploration and development budget for our oil and natural gas properties for the year ending December 31, 2012 is approximately $180.0 million. In 2012, we plan to spend approximately $158.0 million on the drilling and completion of 72 gross (65 net) operated vertical wells and nine gross (eight net) horizontal wells, $8.0 million for the drilling and completion of nine non-operated wells, $8.0 million for leasehold acquisitions and $6.0 million for the construction of infrastructure to support production, including investments in water disposal infrastructure and gathering line projects.

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 March 31, 2012, after giving effect to the Contributions, we had 977 identified potential vertical drilling locations on our acreage in the Permian Basin based on 40-acre spacing and an additional 1,162 such locations based on 20-acre downspacing. We believe the drilling of these locations will provide us with the critical subsurface data necessary to target potential horizontal horizons. Our 2012 drilling plan currently contemplates drilling 72 gross (65 net) vertical wells and nine gross (eight net) horizontal wells in the Wolfberry play. We ended 2011 with a two rig drilling program and are currently using four drilling rigs. We intend to add two additional rigs later in the year. Subject to market conditions and rig availability, we expect to operate up to eight rigs in 2013, which we expect will allow us to significantly increase our drilling program in 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 and we currently plan to drill nine gross (eight net) horizontal wells in 2012 to target these producing horizons. Our 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.

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Focus on enhancing advanced drilling and completion techniques to maximize recovery. Our eight member executive team, which has an average of approximately 26 years of industry experience per person, intends to continue to seek ways to maximize hydrocarbon recovery by refining and enhancing our drilling and completion techniques. The time to reach TD for our vertical Wolfberry wells decreased from an average of 20 days during the second quarter of 2011 to an average of 15 days during the fourth quarter of 2011, resulting in a lower total well cost. Our focus on efficient drilling and completion techniques, and the resulting 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 new 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 86.2% working interest in our acreage pro forma for the Contributions 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. As of December 31, 2011, on a pro forma basis after giving effect to this offering and the use of the net proceeds from this offering to repay borrowings under our revolving credit facility, we would have had approximately $ million of available borrowing capacity under such facility. We expect that we will fund our capital development plans for 2012 from our operating cash flow, proceeds from this offering and borrowings under our revolving credit facility.

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. As of April 27, 2012, the Baker Hughes Rig Count survey reported that there were 510 rigs drilling in the Permian Basin. The majority of our current properties are well positioned in the core of the Wolfberry play. We believe that our historical vertical development success will be complemented with horizontal drilling locations that could ultimately translate into an increased recovery factor on a per section basis.

Our production for the year ended December 31, 2011 was approximately 74% oil, 15% natural gas liquids and 11% natural gas. As of December 31, 2011, our estimated net proved reserves were comprised of approximately 68% oil and 19% 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 March 31, 2012, after giving effect to the Contributions, we had 977 identified potential vertical drilling locations based on 40-acre spacing and an additional 1,162 identified potential vertical drilling locations based on 20-acre downspacing. In 2012, after giving effect to the Contributions, we anticipate drilling 72 gross (65 net) vertical operated wells and nine gross (eight net) horizontal operated wells, which represent only approximately 7.4% of our identified potential vertical drilling locations at March 31, 2012. We also believe that there are multiple horizontal locations that could be drilled on our acreage. In addition, the liquids rich natural gas component of our inventory adds value with Btu content ranging from 1,243 MMBtu to 1,578 MMBtu and our March 2012 natural gas liquids yield was 125 Bbls/MMcf. In addition, we have approximately 117 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 new executive team has an average of approximately 26 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 future development plans to include horizontal drilling. 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 over 400,000 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 processees. This operating control also enables us to obtain data needed for efficient exploration of horizontal prospects.

Financial flexibility to fund expansion. Upon the completion of this offering, we will 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, 2011, on a pro forma basis after giving effect to this offering and the use of the net proceeds from this offering to repay borrowings under our revolving credit facility, we would have had approximately $ million of available borrowing capacity under our revolving credit facility. We expect that our borrowing base will be increased as a result of the Contributions.

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Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. You should read carefully the section of this prospectus entitled *Risk Factors* beginning on page 14 for an explanation of these risks before investing in our common stock. In particular, the following considerations may offset our competitive strengths or have a negative effect on our strategy or operating activities, which could cause a decrease in the price of our common stock and a loss of all or part of your investment:

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

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

Our largest stockholder controls a significant percentage of our common stock and its interests may conflict with yours.

For a discussion of other considerations that could negatively affect us, see *Risk Factors* beginning on page 14 and *Cautionary Note Regarding Forward-Looking Statements* on page 41 of this prospectus.

The Contributions

On May 7, 2012, we entered into a contribution agreement with Gulfport in which Gulfport agreed to contribute to us, prior to the closing of this offering, all of its oil and natural gas interests in the Permian Basin in exchange for (i) shares of our common stock, which will represent 35% of our outstanding common stock immediately prior to the closing of this offering and (ii) approximately $63.6 million in the form of a non-interest bearing promissory note, which we refer to as the Gulfport contribution note, that will be repaid in full upon the closing of this offering with a portion of the net proceeds from this offering. We are the operator of the acreage to be contributed to us by Gulfport. The aggregate consideration payable to Gulfport is subject to a post-closing cash adjustment based on changes in our working capital, long-term debt and certain other items identified in the contribution agreement as of the date of the contribution. Gulfport s obligation to make this contribution is contingent upon, among other things, the contribution to us of all the outstanding equity interests in Windsor Permian and Gulfport s satisfaction with the terms of this offering. In connection with this contribution, we will grant Gulfport the right, for so long as Gulfport beneficially owns more than 10% of our outstanding common stock, to designate one individual as a nominee to serve on our board of directors. We will also grant Gulfport certain demand and piggyback registration rights obligating us to register with the SEC the shares of our common stock owned by Gulfport. For more information about the Gulfport contribution, see *Management Our Board of Directors and Committees*, *Related Party Transactions Gulfport Contribution and Investor Rights Agreement* and *Shares Eligible for Future Sale Registration Rights* beginning on pages 103, 118 and 128, respectively, of this prospectus.

In addition, our equity sponsor, Wexford, has agreed to cause all of the outstanding equity interests in Windsor UT LLC, or Windsor UT, to be contributed to Windsor Permian before it is contributed to us. Windsor UT was formed in April 2010 and acquired 4,978 gross (2,489 net) acres in the Permian Basin. The other 2,489 net acres are owned by Gulfport and will be contributed to us in the Gulfport contribution. Five wells have been drilled on this acreage as of March 31, 2012, which acreage contains 120 of our identified potential vertical drilling locations based on 40-acre spacing.

We refer to Gulfport s contribution of properties to us as the Gulfport contribution and we refer to the Gulfport contribution together with the contribution to Windsor Permian of all the equity interests in Windsor UT as the Contributions.

Our Equity Sponsor

We were formed by our equity sponsor, Wexford Capital LP, or Wexford, which is a Greenwich, Connecticut-based SEC-registered investment advisor with over $5.5 billion under management as of December 31, 2011. Wexford has made public and private equity investments in many different sectors and has particular expertise in the energy and natural resources sector. Upon completion of this offering, Wexford will beneficially own approximately % of our common stock (approximately % if the underwriters option to purchase additional shares is exercised in full). As a result, Wexford will continue to be able to exercise significant control over all matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. Prior to the closing of this offering, we will enter into an advisory services agreement with Wexford under which Wexford will provide us with financial and strategic advisory services related to our business. We are also party to certain other agreements with Wexford and its affiliates. For a description of the advisory services agreement and other agreements with Wexford and its affiliates, see *Related Party Transactions* beginning on page 118. Although our management believes that the terms of these related party agreements are reasonable, it is possible that we could have negotiated more favorable terms for such transactions with unrelated third parties. The existence of these related party agreements may give Wexford the ability to further influence and maintain control over many matters affecting us.

Our History

Diamondback Energy, Inc. was incorporated on December 30, 2011 in Delaware as a holding company and will not conduct any material business operations prior to the transaction described below. All of our historical assets, operations and results described in this prospectus are those of Windsor Permian LLC, or Windsor Permian, which is an entity controlled by our equity sponsor, Wexford. Prior to the completion of this offering, Wexford will cause DB Energy Holdings LLC, or DB Holdings, an entity controlled by Wexford, to contribute all of the outstanding equity interests in Windsor Permian to us in exchange for shares of our common stock. Contemporaneously with this contribution, Gulfport will complete the Gulfport contribution. Upon completion of these contributions, Wexford and Gulfport will beneficially own 65% and 35%, respectively, of our outstanding common stock. Upon completion of the offering, Wexford and Gulfport will beneficially own approximately and %, respectively, of our common stock (approximately % and %, respectively, if the underwriters option to purchase additional shares is exercised in full).

As of April 30, 2012, Windsor Permian held a 22% interest in Bison Drilling and Field Services LLC, or Bison, and a 33% interest in Muskie Holdings LLC, or Muskie. Bison owns drilling rigs and various oil and natural gas well servicing equipment and performs drilling and field services for us. Muskie owns certain assets, real estate and rights in a lease for land that is prospective for oil and natural gas fracture grade sand. Windsor Permian s interests in Bison and Muskie will be distributed to Windsor Permian s sole member prior to the contribution of Windsor Permian to us so we may focus our activities on our oil and natural gas exploration and development activities. We recorded revenues of $0.8 million and $1.5 million attributable to Bison in our consolidated statements of operations during 2010 and the first quarter of 2011, respectively. Muskie was formed in 2011, and we recorded a loss from equity method investments of $7,107 for 2011. The interests in Bison and Muskie are reflected in Investments-equity method on our consolidated balance sheets. For additional information regarding Bison and Muskie, see *Unaudited Pro Forma Condensed Consolidated Financial Statements* and *Related Party Transactions* beginning on pages 48 and 118, respectively, of this prospectus and Note 5 to our consolidated financial statements appearing elsewhere in this prospectus.

Emerging Growth Company

We are an emerging growth company within the meaning of the federal securities laws. For as long as we are an emerging growth company, we will not be required to comply with the requirements that are applicable to other public companies that are not emerging growth companies including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, the reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements and the exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved. We intend to take advantage of these reporting exemptions until we are no longer an emerging growth company. For a description of the qualifications and other requirements applicable to emerging growth companies and certain elections that we have made due to our status as an emerging growth company, see *Risk Factors Risks Related to this Offering and our Common Stock We are an emerging growth company and we cannot be certain if the reduced disclosure requirements applicable to emerging growth companies will make our common stock less attractive to investors* on page 37 of this prospectus.

Our Offices

Our principal executive offices are located at 500 West Texas, Suite 1225, Midland, Texas, and our telephone number at that address is (432) 221-7400. We also lease additional office space in Midland and in Oklahoma City, Oklahoma. Our website address is www.diamondbackenergy.com. Information contained on our website does not constitute part of this prospectus. Except as otherwise indicated or required by the context, all references in this prospectus to Diamondback, the Company, we, us or our relate to Diamondback Energy, Inc and its consolidated subsidiaries after giving effect to the contribution to us of all of the outstanding equity interests in Windsor Permian.

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The Offering

Common stock offered by us	shares (shares if the underwriters option to purchase additional shares is exercised in full)
Common stock offered by the selling stockholders	shares (shares if the underwriters option to purchase additional shares is exercised in full)
Common stock to be outstanding immediately after completion of this offering	shares
Option to purchase additional shares	We and the selling stockholders have granted the underwriters a 30-day option to purchase on a pro rata basis up to an aggregate of additional shares of our common stock.
Use of proceeds	We expect to receive approximately $ million of net proceeds from the sale of the common stock offered by us, based upon the assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus), after deducting underwriting discounts and estimated offering expenses (or approximately $ million if the underwriters option to purchase additional shares is exercised in full). At the closing of this offering, we will use approximately $ million of the net proceeds to repay outstanding borrowings under our revolving credit facility and $63.6 million to repay the Gulfport contribution note. The remaining net proceeds of approximately $ million (or approximately $ million if the underwriters option to purchase additional shares is exercised in full), will be used to fund a portion of our exploration and development activities and for general corporate purposes. We will not receive any proceeds from the sale of shares by the selling stockholders. See *Use of Proceeds* on page 42 of this prospectus.
Dividend policy	We currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future.
NASDAQ Global Market symbol	FANG
Risk Factors	You should carefully read and consider the information beginning on page 14 of this prospectus set forth under the heading *Risk Factors* and all other information set forth in this prospectus before deciding to invest in our common stock.

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

- assumes the underwriters do not exercise their over-allotment option; and excludes shares of common stock reserved for issuance under our equity incentive plan.

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Summary Consolidated Historical and Pro Forma Financial Data

The following table sets forth our summary historical consolidated financial data as of and for each of the periods indicated. The summary consolidated financial data as of December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009 are derived from our historical audited consolidated financial statements included elsewhere in this prospectus. The summary consolidated balance sheet data as of December 31, 2009 are derived from our audited consolidated balance sheet as of that date, which is not included in this prospectus. The unaudited pro forma condensed consolidated financial data give effect to (a) the Contributions and (b) the distribution by Windsor Permian to its equity holder of its minority equity interests in Bison and Muskie. The unaudited pro forma condensed consolidated balance sheet data assume that these transactions occurred on December 31, 2011. The unaudited pro forma condensed consolidated statement of operations data for the year ended December 31, 2011 assume that these transactions occurred on January 1, 2011. The unaudited pro forma C Corporation financial data presented give effect to income taxes assuming we operated as a taxable corporation throughout the periods presented. Operating results for the periods ended December 31, 2011, 2010 and 2009 are not necessarily indicative of results that may be expected for any future periods. You should review this information together with *Management s Discussion and Analysis of Financial Condition and Results of Operations, Selected Historical Consolidated Financial Data* and *Unaudited Pro Forma Condensed Consolidated Financial Statements* beginning on pages 54, 45 and 48, respectively, of this prospectus as well as our consolidated historical financial statements, the historical financial statements of Windsor UT and the statements of revenues and direct operating expenses of certain property interests of Gulfport and their respective related notes included elsewhere in this prospectus.

	Pro Forma Year Ended December 31, 2011	Historical Year Ended December 31, 2011	2010	2009
Statement of Operations Data:				
Oil and natural gas revenues		$ 47,180,802	$ 26,441,927	$ 12,716,011
Other income		1,490,910	811,247	
Expenses:				
Lease operating expense		10,345,355	4,588,559	2,366,623
Production taxes		2,333,853	1,346,879	663,068
Gathering and transportation		201,828	105,870	42,091
Oil and natural gas services		1,732,892	811,247	
Depreciation, depletion and amortization		15,402,826	8,145,143	3,215,891
General and administrative		3,603,479	3,051,627	5,062,618
Asset retirement obligation accretion expense		63,259	37,856	27,934
Total expenses		33,683,492	18,087,181	11,378,225
Income from operations		14,988,220	9,165,993	1,337,786
Other income (expense):				
Interest income		11,197	34,474	35,075
Interest expense		(2,528,058)	(836,265)	(10,938)
Loss on derivative contracts		(13,009,393)	(147,983)	(4,068,005)
Loss from equity investment		(7,017)		
Total other expense, net		(15,533,271)	(949,774)	(4,043,868)
Net (loss) income		$ (545,051)	$ 8,216,219	$ (2,706,082)

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	Pro Forma Year Ended December 31, 2011	Historical Year Ended December 31, 2011	2010	2009
Pro Forma C Corporation Data:[(1)(2)]				
Historical net income (loss) before income taxes	$	$ (545,051)	$ 8,216,219	$ (2,706,082)
Pro forma for income taxes, net of valuation allowance				
Pro forma net income (loss)	$	$ (545,051)	$ 8,216,219	$ (2,706,082)
Pro forma income (loss) per common share basic and diluted		$		
Weighted average pro forma shares outstanding basic and diluted				
Selected Cash Flow and Other Financial Data:				
Net income (loss)		$ (545,051)	$ 8,216,219	$ (2,706,082)
Depreciation, depletion and amortization		15,905,315	8,145,143	3,215,891
Other non-cash items		13,844,010	344,461	4,108,464
Change in operating assets and liabilities		1,179,920	(11,529,999)	(1,916,707)
Net cash provided by operating activities		$ 30,384,194	$ 5,175,824	$ 2,701,566
Net cash used in investing activities		$ (76,314,042)	$ (53,134,641)	$ (32,149,617)
Net cash provided by financing activities		$ 48,642,492	$ 49,618,254	$ 23,849,250

	Pro Forma As of December 31, 2011	Historical As of December 31, 2011	2010	2009
Balance sheet data:				
Cash and cash equivalents		$ 6,802,389	$ 4,089,745	$ 2,430,308
Other current assets		24,130,450	20,947,659	2,263,097
Oil and gas properties, net using full cost method of accounting		206,342,604	135,782,510	89,777,517
Well equipment to be used in development of oil and gas properties				5,413,310
Other property and equipment, net		684,015	11,059,220	105,564
Other assets		11,524,427	637,562	82,813
Total assets		$ 249,483,885	$ 172,516,696	$ 100,072,609
Current liabilities		$ 42,418,305	$ 20,010,276	$ 13,972,080
Note payable credit facility-long term		85,000,000	44,766,687	
Derivative contracts-long term		6,138,573	1,373,864	1,416,431
Asset retirement obligations		1,079,725	727,826	481,887
Member s equity		114,847,282	105,638,043	84,202,211
Total liabilities and member s equity		$ 249,483,885	$ 172,516,696	$ 100,072,609

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	Pro Forma Year Ended December 31, 2011	Historical As of December 31, 2011	2010	2009
Other financial data:				
Adjusted EBITDA(3)		$ 31,505,264	$ 17,383,466	$ 4,616,686

(1) Diamondback Energy, Inc. was incorporated on December 30, 2011 in Delaware as a holding company and will not conduct any material business operations prior to the transaction described below. Our historical consolidated financial statements and other financial information included in this prospectus pertain to assets, liabilities, revenues and expenses of Windsor Permian LLC, which is an entity controlled by our equity sponsor, Wexford. Windsor Permian LLC was treated as a partnership for federal income tax purposes. As a result, essentially all of Windsor Permian LLC s taxable earnings and losses were passed through to Wexford, and Windsor Permian LLC did not pay federal income taxes at the entity level. Prior to the completion of this offering, Windsor Permian LLC will become our wholly-owned subsidiary and, because we are a subchapter C corporation under the Internal Revenue Code, the earnings at Windsor Permian LLC will become subject to federal income tax. For comparative purposes, we have included pro forma financial data to give effect to income taxes net of valuation allowance assuming the earnings at Windsor Permian LLC had been subject to federal income tax as a subchapter C corporation in all periods presented in the accompanying table. If the earnings at Windsor Permian LLC had been subject to federal income tax as a subchapter C corporation during the periods presented herein, we would have incurred net operating losses in each period presented. We would have been in a net deferred tax asset, or DTA, position as a result of such tax losses and would have recorded a valuation allowance to reduce each period s DTA balance to zero. A valuation allowance to reduce each period s DTA would have resulted in an equal and offsetting credit for the respective expenses or an equal and offsetting debit for the respective benefits for income taxes, with the resulting tax expenses for each of the above periods of zero. The unaudited pro forma data is presented for informational purposes only, and does not purport to project our results of operations for any future period or our financial position as of any future date.

(2) Unaudited historical pro forma basic and diluted income (loss) per share will be presented for the latest fiscal year on the basis of the aggregate number of shares to be issued to Gulfport in connection with the Gulfport contribution and to DB Holdings in connection with its contribution to us of all of the outstanding equity interests in Windsor Permian LLC, upon determination of the number of those shares.

(3) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss), see *Selected Historical Consolidated Financial Data* beginning on page 45 of this prospectus.

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Summary Historical and Pro Forma Reserve Data

The following table sets forth estimates of our net proved oil and natural gas reserves as of December 31, 2011 on a historical basis and on a pro forma basis after giving effect to the Contributions as if they had occurred as of December 31, 2011. Our historical reserves and the historical reserves attributable to the Windsor UT properties and the properties subject to the Gulfport contribution have been prepared in each case as of December 31, 2011 by Ryder Scott, an independent petroleum engineering firm, in accordance with SEC rules and regulations. Copies of these reserve reports are attached to this prospectus as Appendices B, C and D. You should also refer to *Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations, Business Oil and Gas Data Proved Reserves, Business Oil and Gas Production Prices and Production Costs Production and Price History* beginning on pages 14, 54, 84 and 88, respectively, of this prospectus, our audited consolidated financial statements and notes thereto and our unaudited pro forma financial statements and notes thereto included in this prospectus in evaluating the material presented below.

	Pro Forma December 31, 2011	Historical December 31, 2011
Estimated proved developed reserves:		
Oil (Bbls)	6,046,099	3,805,291
Natural gas (Mcf)	8,335,945	5,186,941
Natural gas liquids (Bbls)	1,969,711	1,233,319
Total (BOE)	9,405,134	5,903,100
Estimated proved undeveloped reserves:		
Oil (Bbls)	20,140,375	12,911,576
Natural gas (Mcf)	24,261,520	14,431,924
Natural gas liquids (Bbls)	5,870,850	3,529,955
Total (BOE)	30,054,812	18,846,852
Estimated Net Proved Reserves:		
Oil (Bbls)	26,186,474	16,716,867
Natural gas (Mcf)	32,597,465	19,618,865
Natural gas liquids (Bbls)	7,840,561	4,763,274
Total (BOE)[(1)]	39,459,946	24,749,952
Percent proved developed	23.8%	23.9%

(1) Estimates of reserves as of December 31, 2011 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2011, in accordance with revised SEC guidelines applicable to reserves estimates as of the end of 2011. 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. 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.

RISK FACTORS

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

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

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

We were incorporated in Delaware on December 30, 2011. All of our historical oil and natural gas assets, operations and results described in this prospectus are currently those of Windsor Permian, which is an entity controlled by our equity sponsor, Wexford. Immediately prior to the closing of this offering, Windsor Permian will become our wholly-owned subsidiary and we will acquire the oil and gas assets of Gulfport located in the Permian Basin in the Gulfport contribution. The oil and natural gas properties of Windsor Permian, Gulfport and Windsor UT described in this prospectus have been acquired by Windsor Permian, Gulfport and Windsor UT since December 2007. As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

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

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

Approximately 74% 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 74% 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 2011, our total capital expenditures, including expenditures for leasehold interest and property acquisitions, drilling, seismic and infrastructure, were approximately $81.7 million. Our 2012 capital budget for drilling, completion and infrastructure, including investments in water disposal infrastructure and gathering line projects, is estimated to be approximately $180.0 million. To date, we have financed capital expenditures primarily with funding from our equity sponsor, borrowings under our revolving credit facility and cash generated by operations.

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

- our proved reserves;
- the volume of oil and natural gas we are able to produce from existing wells;
- the prices at which 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 2012 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 otherwise 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 undertake our exploration, development and production activities or the acquisition of oil and natural gas reserves, our exploratory projects or other replacement 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 March 31, 2012, after giving effect to the Contributions, we drilled a total of 147 gross wells and participated in an additional 11 gross non-operated wells, of which 149 wells were completed as producing wells and nine wells were in various stages of completion. If the wells in the process of being completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected.

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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 March 31, 2012, after giving effect to the Contributions, we had 977 identified potential vertical drilling locations on our existing acreage based on 40-acre spacing and an additional 1,162 identified potential vertical drilling locations based on 20-acre downspacing. Only 329 of these identified potential vertical 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 March 31, 2012 after giving effect to the Contributions, we had leases representing 250 net acres expiring in 2012, 222 net acres expiring in 2013, 2,041 net acres expiring in 2014 and 13,628 net acres expiring in 2015. 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. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business.

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 primarily 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;

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- 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;
- 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 $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in January 2006. During 2011, prices ranged from $75.67 to $113.93 per Bbl for oil and wellhead natural gas market prices ranged from $2.79 to $4.92 per Mcf. On March 31, 2012, the West Texas Intermediate posted price for crude oil was $103.02 per Bbl and the Henry Hub spot market price of natural gas was $2.02 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.

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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. 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 price of $78.50 per barrel in 2012 and $80.55 per barrel in 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 $12.7 million at December 31, 2011) and receivables from purchasers of our oil and natural gas production (approximately $5.0 million at December 31, 2011). 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 years ended December 31, 2011 and 2010, one purchaser, Windsor Midstream LLC, an entity controlled by Wexford, our equity sponsor, accounted for approximately 78.4% and 81.7% of our revenue, respectively. For the year ended December 31, 2009, two purchasers accounted for more than 10% of our revenue: Windsor Midstream LLC (68.3%) and DCP Midstream, LP (14.8%). 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 based on proved reserves. The average depletion rate per barrel equivalent unit of production was $25.40, $17.78 and $11.21 for the years ended December 31, 2011, 2010 and 2009, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties for the years ended December 31, 2011, 2010 and 2009 was $15.2 million, $7.4 million and $3.2 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, 2011, 2010 and 2009. We may experience additional ceiling test write downs in the future. See *Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Method of accounting for oil and natural gas properties* beginning of page 71 of this prospectus for a more detailed description of our method of accounting.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Oil and natural gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, ultimate recoveries and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may be incorrect. Our historical estimates of proved reserves and related valuations are based on reports prepared by Ryder Scott as of December 31, 2011 and by Pinnacle as of December 31, 2010 and 2009, each an independent petroleum engineering firm. The estimates of proved reserves and related valuations attributable to the Windsor UT properties and the properties subject to the Gulfport contribution are based, in each case, on reports prepared by Ryder Scott as of December 31, 2011. 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 the 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 we ultimately recover being different from our reserve estimates.

The estimates of reserves as of December 31, 2011, 2010 and 2009 included in this prospectus were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2011, 2010 and 2009, 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.

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

SEC rules 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 76% of our total estimated proved reserves at December 31, 2011 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 engineer reports assumes 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 future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify 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 one major 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, 2011, 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.

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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 years ended December 31, 2011 and 2010, one purchaser, Windsor Midstream LLC, an entity controlled by Wexford, our equity sponsor, accounted for approximately 78.4% and 81.7% of our revenue, respectively. For the year ended December 31, 2009, two purchasers accounted for more than 10% of our revenue: Windsor Midstream LLC (68.3%) and DCP Midstream, LP (14.8%). 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, we intend to increase the number of rigs we have operating in 2012 and 2013. 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 declining 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

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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 continues to deteriorate, 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 $0.5 million for the year ended December 31, 2011. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures. The uncertainty and risks described in this prospectus may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by 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 drilling and completion technique risks 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 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 natural gas and oil prices decline, 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 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 gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. When these facilities are unavailable, our operations can 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 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, would adversely affect our financial condition and results of operations.

Our operations are subject to various governmental 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 *Business Regulation Environmental Matters and Regulation* and *Business Regulation Other Regulation of the Oil and Natural Gas Industry* beginning on pages 92 and 96, respectively, of this prospectus for a description of the laws and regulations that affect us.

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

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

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hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. 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, both the EPA and the House committee have 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 Safe Drinking Water Act 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 Safe Drinking Water Act.

On April 17, 2012, 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, 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 includes a 95 percent 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 2012 and 2014.

These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities.

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 the well operator disclose the list of chemical ingredients subject to the requirements of 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. 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 use of fracturing fluids, impacts on drinking water supplies, use of waters 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

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hydraulic fracturing, such as the FRAC Act, 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.

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 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, production and transporting product pipelines or other operations; regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or 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 spills or releases from our operations could expose us to significant liabilities under environmental 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 recent 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 recent 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 recently 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 new legislation was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the new legislation, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. Although the CFTC has promulgated numerous final rules based on its proposals, it is not possible at this time to predict when the CFTC will finalize its proposed regulations or the effect of such regulations on our business. 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 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.

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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 in April 2010 and it became effective January 2011, although it does not require immediate reductions in GHG emissions. The EPA adopted the stationary source rule, also known as the Tailoring Rule, in May 2010, and it also became effective January 2011, although it remains subject of several pending lawsuits filed by industry groups. 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. 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 new 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 the Gulfport contribution, Wexford will beneficially own 100% of our equity interests. Upon completion of this offering, Wexford will beneficially own approximately % of our common stock, or % if the underwriters exercise in full their option to purchase additional shares. See *Principal and Selling Stockholders* beginning on page 122 of this prospectus. Further, we anticipate that several individuals who will serve as our directors upon completion of this offering will be 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 Holdings following the completion of this offering, Wexford will not be subject to any obligation to maintain its ownership interest in us and may elect at any time thereafter to sell all or a substantial portion of or otherwise reduce its ownership interest in us. If Wexford sells all or a substantial portion of its ownership interest in us, Wexford may have less incentive to assist in our success and its affiliate(s) that are expected to 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.

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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.

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, 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 investigation and penalties, suspension of operations and repairs 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 the 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 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 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. 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 early as 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 upon becoming a large accelerated filer, as defined in the SEC rules, or otherwise ceasing 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 the 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. For example, we anticipate the need to hire additional administrative and accounting personnel to conduct our financial reporting.

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 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 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 can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in 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

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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 2011 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 $0.5 million of compensation expense in 2011. 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 anticipated stock-based incentive plans. These additional expenses will adversely affect our net income. We cannot determine the actual amount of these new stock-related compensation and benefit expenses at this time because applicable accounting practices generally require that they be based on the fair market 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 would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

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

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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 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 December 31, 2011, the weighted average interest rate on outstanding borrowings under our revolving credit facility was 3.3%. 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 $100.0 million borrowing base, we are subject to semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves. Our revolving credit facility currently provides that the borrowing base will remain at $100.0 million through October 15, 2012, at which time the borrowing base will be reduced to $85.0 million, subject to the periodic and elective borrowing base redeterminations discussed above, and without consideration of the impact of the Gulfport contribution and the Windsor UT properties. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow.

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

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

A terrorist attack or armed conflict could harm our business.

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

Risks Related to this Offering and Our Common Stock

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

Upon completion of this offering, Wexford and Gulfport will beneficially own approximately % and %, respectively, of our common stock, or % and %, respectively, if the underwriters exercise their option to purchase additional shares in full. See *Principal and Selling Stockholders* beginning on page 122 of this prospectus. In addition, individuals affiliated with Wexford and Gulfport serve on our Board of Directors, and Gulfport has the right to designate one individual as a nominee for election to our Board of Directors so long as it continues to beneficially own more than 10% of our outstanding common stock. As a result, Wexford and Gulfport, together, will be 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.

Since we are a controlled company for purposes of The NASDAQ Global Market s corporate governance requirements, our stockholders will not have, and may never have, the protections that these corporate governance requirements are intended to provide.

Since we are a controlled company for purposes of The NASDAQ Global Market s corporate governance requirements, we are not required to comply with the provisions requiring that a majority of our directors be independent, the compensation of our executives be determined by independent directors or nominees for election to our board of directors be selected by independent directors. If we choose to take advantage of any or all of these exemptions, our stockholders may not have the protections that these rules are intended to provide.

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

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

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

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

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

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies. As described under the caption *Related Party Transactions* beginning on page 118 of this prospectus, these include, among others, drilling services provided to us to 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 entites is either controlled by or affiliated with Wexford, and the resolution of any conflicts that may arise in connection with such related party transactions, including pricing, duration or other terms of service, may not always be in our or our stockholders best interests because Wexford may have the ability to influence the outcome of these conflicts. For a discussion of potential conflicts, see *Risks Related to this Offering and our Common Stock Our two largest stockholders control a significant percentage of our common stock, and their interests may conflict with those of our other stockholders* on page 35 of this prospectus.

We will incur increased costs as a result of being a public company, which may significantly affect our financial condition.

As a public company, we will incur significant legal, accounting and other expenses that we did not incur as a private company. We will incur costs associated with our public company reporting requirements. We also anticipate that we will incur costs associated 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. We expect these rules and regulations to increase our legal and financial compliance costs and to make some activities more time-consuming and costly, particularly after we are no longer an emerging growth company. We also expect these rules and regulations may 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. We are currently evaluating these rules, and we cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

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 shareholder 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* on page 32 of this prospectus.

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

We are 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. We cannot predict if investors will find our common stock less attractive because we will 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.

There has been no public market for our common stock and if the price of our common stock fluctuates significantly, your investment could lose value.

Prior to this offering, there has been no public market for our common stock. Although we have applied to have our common stock listed on The NASDAQ Global Market, we cannot assure you that an active public market will develop for our common stock or that our common stock will trade in the public market subsequent to this offering at or above the initial public offering price. If an active public market for our common stock does not develop, 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 is 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. The initial offering price, which will be negotiated between us and the underwriters, may not be indicative of the trading price for our common stock after this offering. In addition, 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 change.

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 after this offering, or the perception that these sales may occur, could cause the market price of our common stock to decline. See *Shares Eligible for Future Sale* on page 127 of this prospectus. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock. After this offering, we will have shares of common stock outstanding, excluding stock options. All of the shares sold in this offering, except for any shares purchased by our affiliates, will be freely tradable.

DB Holdings, Gulfport and our directors and executive officers will be 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 the date of this prospectus, 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. 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 downgrades our stock or if our operating results do not meet their expectations, our stock price could decline.

Purchasers in this offering will experience immediate dilution and will experience further dilution with the future exercise of stock options granted to certain of our executive officers under their respective employment agreements.

The initial public offering price is substantially higher than the pro forma net tangible book value per share of our outstanding common stock. As a result, you will experience immediate and substantial dilution of

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approximately $ per share, representing the difference between our net tangible book value per share as of after giving effect to this offering and an assumed initial public offering price of $ (which is the midpoint of the range set forth on the cover of the prospectus). A $1.00 increase (decrease) in the assumed initial public offering price of $ per share (which is the midpoint of the range set forth on the cover page of this prospectus) would increase (decrease) our net tangible book value per share after giving effect to this offering by $, and increase (decrease) the dilution to new investors by $, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting the estimated underwriting discounts and commissions and estimated offered expenses payable by us. If the options granted to certain of our executive officers under their respective employment agreements are exercised in full, the investors in this offering will experience further dilution. See *Dilution* beginning on page 44 of this prospectus for a description of dilution.

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.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

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

All of these types of statements, other than statements of historical fact included in this prospectus, are forward-looking statements. These forward-looking statements may be found in the *Prospectus Summary,* *Risk Factors,* *Management s Discussion and Analysis of Financial Condition and Results of Operations* and *Business* beginning on pages 1, 14, 54 and 77, respectively, and other sections of this prospectus. In some cases, you can identify forward-looking statements by terminology such as may, could, should, expect, plan, project, anticipate, believe, estimate, predict, potential, pursue, target, seek, objective or continue, the negative of such terms or other terminology.

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

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USE OF PROCEEDS

Our net proceeds from the sale of shares of common stock in this offering, assuming a public offering price of $ per share (which is the midpoint of the range set forth on the cover of this prospectus), are estimated to be $ million, after deducting underwriting discounts and commissions and estimated offering expenses. The net proceeds would be $ million if the underwriters option to purchase additional shares is exercised in full. At the closing of this offering, we intend to use approximately $ million of the net proceeds to repay outstanding borrowings under our revolving credit facility and $63.6 million to repay the Gulfport contribution note and, thereafter, we intend to use the balance of the proceeds from this offering to fund a portion of our exploration and development activities and for general corporate purposes, which may include leasehold interest and property acquisitions, working capital and the settlement of crude oil swaps. Upon repayment of the outstanding borrowings under our revolving credit facility, we will have $ million of borrowing capacity under that facility to further fund our exploration and development activities and for general corporate purposes.

All borrowings under our revolving credit facility are due and payable on October 14, 2014. As of April 30, 2012, $100.0 million was outstanding under our revolving credit facility and bore interest at a weighted average rate of 3.3% per annum. The amounts initially borrowed under our revolving credit facility were used to repay in full the outstanding indebtedness under our prior credit facility and for general corporate purposes. The Gulfport contribution note, which will be issued immediately prior to the closing of this offering in connection with the Gulfport contribution, does not bear interest and is due upon completion of this offering.

We will not receive any proceeds from the sale of shares by the selling stockholders, including any sale the selling stockholders may make upon exercise of the underwriters option to purchase additional shares.

An increase or decrease in the initial public offering price of $1.00 per share would cause the net proceeds that we will receive in this offering to increase or decrease by approximately $ million. If our net proceeds are reduced, we will have less proceeds to fund our exploration and development activities and may not have sufficient funds to repay our revolving credit facility in full. Any reduction in net proceeds may cause us to need to borrow additional funds under our revolving credit facility to fund our operations, which would increase our interest expense and decrease our net income.

DIVIDEND POLICY

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

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CAPITALIZATION

The following table sets forth our cash and cash equivalents and capitalization as of December 31, 2011:

- on an actual basis;
- on a pro forma basis to give effect to the issuance of (a) shares of our common stock to an affiliate of Wexford in exchange for its contribution to us of all the outstanding equity interests in Windsor Permian, (b) shares of our common stock and the Gulfport contribution note to Gulfport in connection with the Gulfport contribution and (c) the distribution by Windsor Permian to its equity holders of its minority equity interests in Bison and Muskie; and
- on a pro forma basis described above as adjusted to give effect to the sale of shares of our common stock in this offering at an assumed initial public offering price of $ per share (which is the midpoint of the range set forth on the cover of this prospectus), our receipt of an estimated $ million of net proceeds from this offering after deducting underwriting discounts and commissions and estimated offering expenses and the use of a portion of those proceeds to repay outstanding borrowings as described under the caption *Use of Proceeds* on page 42 of this prospectus.

You should read the following table in conjunction with *Management s Discussion and Analysis of Financial Condition and Results of Operations* beginning on page 54 and our consolidated financial statements and related notes appearing elsewhere in this prospectus.

	As of December 31, 2011		
	Actual(1)	**Pro Forma**	**Pro Forma As Adjusted(2)**
		(in thousands)	
Cash and cash equivalents	$ 6,802	$	$
Long term debt (including current maturities)(3)	$ 85,000	$	$
Member s equity	114,847		
Stockholders equity:			
Common stock, par value $0.01; 100 shares authorized and shares issued and outstanding actual; shares authorized and shares issued and outstanding as adjusted for the offering			
Additional paid-in capital			
Accumulated deficit(4)			
Total stockholders equity			
Total capitalization	$ 199,847	$	$

(1) Diamondback Energy, Inc. was incorporated on December 30, 2011 in Delaware as a holding company and will not conduct any material business operations prior to the completion of the offering. The data in this table has been derived from the historical consolidated financial statements and other financial information included in this prospectus which pertain to the assets, liabilities, revenues and expenses of Windsor Permian LLC. Immediately prior to the completion of this offering, Windsor Permian LLC will become our wholly-owned subsidiary.

(2) A $1.00 increase (decrease) in the assumed initial public offering price of $ per share (which is the midpoint of the range set forth on the cover of this prospectus) would increase (decrease) each of cash and cash equivalents, additional paid-in-capital and total capitalization by $, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after

deducting the estimated underwriting discounts and commissions and estimated offering expenses payable by us.

(3) At April 30, 2012, long term debt was $100.0 million.

(4) Upon completion of this offering, we will recognize deferred tax liabilities and assets for temporary differences between the historical cost basis and tax basis of these assets and liabilities. Based on estimates of those temporary differences as of December 31, 2011, a net deferred tax liability of approximately $26.2 million will be recognized with a corresponding charge to earnings.

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DILUTION

Our reported net tangible book value as of December 31, 2011 was $ million, or $ per share, based upon shares outstanding as of that date after giving pro forma effect to (a) the contribution to us of all of the outstanding equity interests in Windsor Permian, (b) the Gulfport contribution and (c) the distribution by Windsor Permian to its equity holders of its minority equity interests in Bison and Muskie. Net tangible book value per share is determined by dividing such number of outstanding shares of common stock into our net tangible book value, which is our total tangible assets less total liabilities. Assuming the sale by us of shares of common stock offered in this offering at an estimated initial public offering price of $ per share (which is the midpoint of the range set forth on the cover of this prospectus) and after deducting the underwriting discounts and commissions and estimated offering expenses payable by us, our net tangible book value as of December 31, 2011 would have been approximately $ million, or $ per share, after giving pro forma effect to (a) the contribution to us of all of the outstanding equity interests in Windsor Permian, (b) to the Gulfport contribution and (c) the distribution by Windsor Permian to its equity holders of its minority equity interests in Bison and Muskie. This represents an immediate increase in net tangible book value of $ per share to our existing stockholders and an immediate dilution of $ per share to new investors purchasing shares at the initial public offering price.

The following table illustrates the per share dilution:

Assumed initial public offering price per share		$
Pro forma net tangible book value per share as of December 31, 2011	$	
Increase per share attributable to new investors	$	
As adjusted net tangible book value per share after the offering		$
Dilution per share to new investors		$

A $1.00 increase (decrease) in the assumed initial public offering price of $ per share (which is the midpoint of the range set forth in the cover of this prospectus) would increase (decrease) our net tangible book value after the offering by $, and increase (decrease) the dilution to new investors by $, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting the estimated underwriting discounts and commissions and estimated offering expenses payable by us.

The following table sets forth, as of December 31, 2011, after giving pro forma effect to the contribution to us by DB Holdings of all of the outstanding equity interests in Windsor Permian and to the Contributions, the number of shares of common stock to be issued by us to DB Holdings and Gulfport, which will be our existing stockholders immediately prior to this offering, and by the new investors at the assumed initial public offering price of $ per share, together with the total consideration paid and average price per share paid by each of these groups, before deducting underwriting discounts and commissions and estimated offering expenses.

	Shares Purchased		Total Consideration		Average Price
	Number	Percent	Amount	Percent	Per Share
Existing stockholders		%	$	%	$
New investors		%		%	
Total		100.0%	$	100.0%	$

If the underwriters option to purchase additional shares is exercised in full, the number of shares held by new investors will be increased to , or approximately % of the total number of shares of common stock.

The data in the table excludes shares of common stock reserved for issuance under our equity incentive plan.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following selected historical consolidated financial data as of December 31, 2011 and 2010 and for each of the years in the three-year period ended December 31, 2011 are derived from our audited consolidated financial statements included elsewhere in this prospectus. The selected consolidated balance sheet data as of December 31, 2009 and 2008 and the selected historical consolidated financial data for 2008 and the period from inception on October 23, 2007 to December 31, 2007 are derived from our audited financial statements not included in this prospectus. The balance sheet data as of December 31, 2007 is derived from our unaudited financial statements not included in this prospectus. The unaudited pro forma data presented gives effect to income taxes assuming that the Company operated as a taxable corporation throughout the periods presented. Operating results for the periods ended December 31, 2011, 2010, 2009, 2008 and 2007 are not necessarily indicative of results that may be expected for any future periods. You should review this information together with *Management s Discussion and Analysis of Financial Condition and Results of Operations* beginning on page 54 and our historical consolidated financial statements and related notes included elsewhere in this prospectus.

	Year Ended December 31,				Period from Inception (October 23, 2007) to December 31, 2007
	2011	**2010**	**2009**	**2008**	
Statement of Operations Data:					
Oil and natural gas revenues	$ 47,180,802	$ 26,441,927	$ 12,716,011	$ 18,238,692	$ 578,336
Other income	1,490,910	811,247			
Expenses:					
Lease operating expense	10,345,355	4,588,559	2,366,623	3,375,419	25,684
Production taxes	2,333,853	1,346,879	663,068	1,008,991	136,077
Gathering and transportation	201,828	105,870	42,091	53,407	2,637
Oil and natural gas services	1,732,892	811,247			
Depreciation, depletion and amortization	15,402,826	8,145,143	3,215,891	10,199,581	138,066
Impairment of oil and gas properties				83,164,230	
General and administrative	3,603,479	3,051,627	5,062,618	5,459,874	6,609
Asset retirement obligation accretion expense	63,259	37,856	27,934	23,569	514
Total expenses	33,683,492	18,087,181	11,378,225	103,285,071	309,587
Income (loss) from operations	14,988,220	9,165,993	1,337,786	(85,046,379)	268,749
Other income (expense):					
Interest income	11,197	34,474	35,075	625,086	23,581
Interest expense	(2,528,058)	(836,265)	(10,938)		
Loss on derivative contracts	(13,009,393)	(147,983)	(4,068,005)	(9,528,220)	(4,791,587)
Loss from equity investment	(7,017)				
Total other expense, net	(15,533,271)	(949,774)	(4,043,868)	(8,903,134)	(4,768,006)
Net income (loss)	$ (545,051)	$ 8,216,219	$ (2,706,082)	$ (93,949,513)	$ (4,499,257)
Pro Forma C Corporation Data:(1)(2)					
Historical net income (loss) before income taxes	$ (545,051)	$ 8,216,219	$ (2,706,082)	$ (93,949,513)	$ (4,499,257)
Pro forma for income taxes, net of valuation allowance					
Pro forma net income (loss)	$ (545,051)	$ 8,216,219	$ (2,706,082)	$ (93,949,513)	$ (4,499,257)
Pro forma income (loss) per common share basic and diluted	$				

Weighted average pro forma shares outstanding basic and diluted	

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	Year Ended December 31,				Period from Inception (October 23, 2007) to December 31,
	2011	2010	2009	2008	2007
Selected Cash Flow and Other Financial Data:					
Net income (loss)	$ (545,051)	$ 8,216,219	$ (2,706,082)	$ (93,949,513)	$ (4,499,257)
Depreciation, depletion and amortization	15,905,315	8,145,143	3,215,891	10,199,581	138,066
Other non-cash items	13,844,010	344,461	4,108,464	92,716,019	4,792,101
Change in operating assets and liabilities	1,179,920	(11,529,999)	(1,916,707)	3,076,317	(2,448,557)
Net cash provided by (used in) operating activities	$ 30,384,194	$ 5,175,824	$ 2,701,566	$ 12,042,404	$ (2,017,647)
Net cash used in investing activities	$ (76,314,042)	$ (53,134,641)	$ (32,149,617)	$ (84,196,562)	$ (86,863,149)
Net cash provided by financing activities	$ 48,642,492	$ 49,618,254	$ 23,849,250	$ 80,182,600	$ 88,881,463

	As of December 31,				
	2011	2010	2009	2008	2007
Balance sheet data:					
Cash and cash equivalents	$ 6,802,389	$ 4,089,745	$ 2,430,308	$ 8,029,109	$ 667
Other current assets	24,130,450	20,947,659	2,263,097	1,389,810	2,489,231
Oil and gas properties, net using full cost method of accounting	206,342,604	135,782,510	89,777,517	73,786,284	83,375,502
Well equipment to be used in development of oil and gas properties			5,413,310	8,503,178	
Other property and equipment, net	684,015	11,059,220	105,564	161,103	
Other assets	11,524,427	637,562	82,813		
Total assets	$ 249,483,885	$ 172,516,696	$ 100,072,609	$ 91,869,484	$ 85,865,400
Current liabilities	$ 42,418,305	$ 20,010,276	$ 13,972,080	$ 18,011,452	$ 126,757
Note payable credit facility-long term	85,000,000	44,766,687			
Derivative contracts-long term	6,138,573	1,373,864	1,416,431	2,868,452	1,141,587
Asset retirement obligations	1,079,725	727,826	481,887	374,287	214,850
Members equity	114,847,282	105,638,043	84,202,211	70,615,293	84,382,206
Total liabilities and members equity	$ 249,483,885	$ 172,516,696	$ 100,072,609	$ 91,869,484	$ 85,865,400

	Year Ended December 31,				Period from Inception (October 23, 2007) to December 31,
	2011	2010	2009	2008	2007
Other financial data:					
Adjusted EBITDA[3]	$ 31,505,264	$ 17,383,466	$ 4,616,686	$ 8,966,087	$ 430,910

(1) Diamondback Energy, Inc. was incorporated on December 30, 2011 in Delaware as a holding company and will not conduct any material business operations prior to the transaction described below. Our historical consolidated financial statements and other financial information included in this prospectus pertain to assets, liabilities, revenues and expenses of Windsor Permian LLC, which is an entity controlled by our equity sponsor, Wexford. Windsor Permian LLC was treated as a partnership for federal income tax purposes. As a result, essentially all of Windsor Permian LLC s taxable earnings and losses were passed through to Wexford, and Windsor Permian LLC did not pay federal income taxes at the entity level. Prior to the completion of this offering, Windsor Permian LLC will become our wholly-owned subsidiary and, because we are a subchapter C corporation under the Internal Revenue Code, the earnings at Windsor Permian LLC will become

subject to federal income tax. For comparative purposes, we have included pro forma financial data to give effect to income taxes net of valuation allowance assuming the earnings of Windsor Permian LLC had been subject to federal income tax as a subchapter C corporation in all periods presented in the accompanying table. If the earnings of Windsor Permian LLC had been subject to federal income tax as a subchapter C corporation during the periods presented herein, we would have incurred net operating losses in each period presented. We would have been in a net deferred tax asset, or DTA, position as a result of such tax losses and would have recorded a valuation allowance to reduce each period s DTA balance to zero. A

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valuation allowance to reduce each period s DTA would have resulted in an equal and offsetting credit for the respective expenses or an equal and offsetting debit for the respective benefits for income taxes, with the resulting tax expenses for each of the above periods of zero. The unaudited pro forma data is presented for informational purposes only, and does not purport to project our results of operations for any future period or our financial position as of any future date.

(2) Unaudited pro forma basic and diluted income (loss) per share will be presented for the latest fiscal year on the basis of the aggregate number of shares to be issued to Gulfport in connection with the Gulfport contribution and to DB Holdings in connection with its contribution to us of all of the outstanding equity interests in Windsor Permian LLC to us, upon determination of the number of those shares.

(3) 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 loss on derivative contracts, 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 tables present a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measure of net income (loss).

	Year Ended December 31,				Period from Inception (October 23, 2007) to December 31,
	2011	**2010**	**2009**	**2008**	**2007**
Reconciliation of Adjusted EBITDA to net income (loss):					
Net income (loss)	$ (545,051)	$ 8,216,219	$ (2,706,082)	$ (93,949,513)	$ (4,499,257)
Loss on derivative contracts	13,009,393	147,983	4,068,005	9,528,220	4,791,587
Interest expense	2,528,058	836,265	10,938		
Depreciation, depletion and amortization	15,905,315	8,145,143	3,215,891	10,199,581	138,066
Impairment of oil and gas properties				83,164,230	
Equity-based compensation expense	544,290				
Asset retirement obligation accretion expense	63,259	37,856	27,934	23,569	514
Adjusted EBITDA	$ 31,505,264	$ 17,383,466	$ 4,616,686	$ 8,966,087	$ 430,910

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UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Diamondback Energy, Inc.

Unaudited Pro Forma Condensed Consolidated Financial Statements

Introduction

The following unaudited pro forma condensed consolidated financial statements and related notes of the Company have been prepared to show the effect of the Contributions and the distribution by Windsor Permian to its equity holders of its minority equity interests in Bison and Muskie. The unaudited pro forma condensed consolidated financial statements should be read together with the historical financial statements of Windsor Permian and Windsor UT and the historical Statements of Revenues and Direct Operating Expenses of certain property interests of Gulfport Energy Corporation included in this prospectus. The accompanying unaudited pro forma condensed consolidated financial statements are based on assumptions and include adjustments as explained in the accompanying notes. The acquisition of certain property interests of Gulfport Energy Corporation (the Gulfport properties) will be treated as a business combination accounted for under the acquisition method of accounting with the identifiable assets recognized at fair value on the date of transfer. The Windsor UT contribution is treated as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in the accounts of the transferring entity at the date of transfer. The pro forma data presented reflect events directly attributable to the Contributions and other described transactions and certain assumptions the Company believes are reasonable. The pro forma data are not necessarily indicative of financial results that would have been attained had the described transactions occurred on the dates indicated below. The pro forma data also necessarily exclude various operation expenses related to the Gulfport properties and the financial statements should not be viewed as indicative of operations in future periods.

The unaudited pro forma condensed consolidated balance sheet assumes that the Contributions and other described transactions occurred on December 31, 2011. The unaudited pro forma condensed consolidated statement of operations for the year ended December 31, 2011 assumes that the Contributions and other described transactions occurred on January 1, 2011.

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Diamondback Energy, Inc.

Unaudited Pro Forma Condensed Consolidated Balance Sheets

December 31, 2011

Assets	Windsor Permian Historical	Windsor UT Historical	Pro Forma Adjustments	Pro Forma
Cash and cash equivalents	$ 6,802,389	$ 156,733	$	$
Other current assets	24,130,450	214,633		
Total current assets	30,932,839	371,366		
Oil and natural gas properties, net using full cost method of accounting	206,342,604	14,122,632	(a)	
Other property and equipment	684,015			
Other assets	11,524,427		(b)	
Total assets	$ 249,483,885	$ 14,493,998		
Liabilities and Members Equity				
Current liabilities	$ 42,418,305	$ 280,383	(a)	
Note payable credit facility-long term	85,000,000			
Derivative contracts-long term	6,138,573			
Asset retirement obligations	1,079,725	24,267	(c)	
Members equity	114,847,282	14,189,348	(a)(c)	
Total liabilities and members equity	$ 249,483,885	$ 14,493,998	$	$

The accompanying notes are an integral part of these unaudited pro forma condensed consolidated financial statements.

Diamondback Energy, Inc.

Unaudited Pro Forma Condensed Consolidated Statement of Operations

Year ended December 31, 2011

	Windsor Permian Historical	Gulfport Contribution Historical	Windsor UT Historical	Pro Forma Adjustments	Pro Forma
Revenues:					
Oil and natural gas revenues	$ 47,180,802	$ 23,052,000	$ 694,666	$	$
Oil and natural gas services	1,490,910			(b)	
Total revenues	48,671,712	23,052,000	694,666		
Costs and expenses:					
Lease operating expenses	10,345,355	5,484,000	251,824		
Production taxes	2,333,853	1,276,000	32,016		
Gathering and transportation	201,828				
Oil and natural gas services	1,732,892			(b)	
Depreciation, depletion and amortization	15,402,826		198,712	(d)	
General and administrative expenses	3,603,479		37,044		
Asset retirement obligation accretion expense	63,259		1,255	(c)	
Total costs and expenses	33,683,492	6,760,000	520,851		
Income from operations	14,988,220	16,292,000	173,815		
Other income (expense)					
Interest income	11,197				
Interest expense	(2,528,058)				
Loss on derivative contracts	(13,009,393)				
Loss from equity investment	(7,017)				
Total other expense, net	(15,533,271)				
Net income (loss)	$ (545,051)	$ 16,292,000	$ 173,815	$	$

The accompanying notes are an integral part of these unaudited pro forma condensed consolidated financial statements.

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Diamondback Energy, Inc

Notes to Unaudited Pro Forma Condensed Consolidated

Financial Statements

1. Basis of Presentation

The historical financial information is derived from the historical financial statements of Windsor Permian and Windsor UT and the historical statements of revenues and direct operating expenses of certain property interests of Gulfport. The unaudited pro forma condensed consolidated balance sheet as of December 31, 2011 has been prepared as if the Contributions and other described transactions had taken place on December 31, 2011. The unaudited pro forma condensed consolidated statement of operations for the year ended December 31, 2011 assumes that the Contributions and other described transactions had occurred on January 1, 2011.

2. Pro Forma Assumptions and Adjustments

We made the following adjustments in the preparation of the unaudited pro forma condensed consolidated financial statements.

(a) To record the contribution of the Gulfport properties at fair value for shares of our common stock, which will represent 35% of our outstanding common stock immediately prior to the closing of this offering, and $63,590,050 in the form of a non-interest bearing promissory note that will be repaid in full upon the closing of this offering. The allocation of the purchase price to the assets acquired is preliminary and, therefore, subject to change.

(b) To record the distribution of minority equity interests in Bison and Muskie to Windsor Permian s sole member prior to the contribution of Windsor Permian to us.

(c) To record incremental accretion of discount on asset retirement obligation associated with the Contributions.

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

3. Oil and Natural Gas Producing Activities

The following table presents estimated unaudited pro forma volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2011 and changes in proved reserves during the year, assuming continuation of economic conditions prevailing at the end of the year. The weighted average prices at December 31, 2011 used for reserve report purposes are $93.09 per Bbl of oil, $56.62 per Bbl of natural gas liquids and $3.96 per Mcf of natural gas, respectively.

The Company emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

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	Year Ended December 31, 2011											
	Windsor Permian Historical			Gulfport Contribution Historical			Windsor UT Historical			Total Pro Forma		
	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)
Proved Developed and Undeveloped Reserves:												
As of January 1, 2011	18,819	5,564	21,662	9,358	3,107	11,926	811	269	1,033	28,988	8,940	34,621
Extensions, discoveries and other additions	1,706	448	1,824	764	217	992	94	18	60	2,564	683	2,876
Revisions of prior reserve estimates	(3,366)	(1,162)	(3,454)	(1,828)	(474)	(599)	487	(1)	(160)	(4,707)	(1,637)	(4,213)
Production	(442)	(87)	(413)	(208)	(59)	(273)	(8)			(658)	(146)	(686)
As of December 31, 2011	16,717	4,763	19,619	8,086	2,791	12,046	1,384	286	933	26,187	7,840	32,598
Proved Developed Reserves:												
January 1, 2011	3,308	1,105	4,255	1,840	794	3,048	64	21	82	5,212	1,920	7,385
December 31, 2011	3,805	1,233	5,187	2,097	706	3,050	144	30	99	6,046	1,969	8,336
Proved Undeveloped Reserves:												
January 1, 2011	15,511	4,459	17,407	7,518	2,313	8,878	747	248	951	23,776	7,020	27,236
December 31, 2011	12,912	3,530	14,432	5,989	2,085	8,996	1,240	256	834	20,141	5,871	24,262

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Diamondback Energy, Inc

Notes to Unaudited Pro Forma Condensed Consolidated

Financial Statements

The following pro forma standardized measure of discounted estimated future net cash flows and changes therein relating to the combined proved oil and natural gas reserves of Windsor Permian and the Contributions as of and for the year ended December 31, 2011 were made in accordance with the provisions of the FASB ASU 2010-03, Extractive Activities Oil and Gas (Topic 932).

	Year Ended December 31, 2011			
	Windsor Permian Historical	Gulfport Contribution Historical	Windsor UT Historical	Total Pro Forma
Future cash flows	$ 1,901,127,669	$ 960,918,000	$ 148,561,297	$ 3,010,606,966
Future development costs	(373,750,257)	(236,336,000)	(36,600,000)	(646,686,257)
Future production costs	(458,939,218)	(166,899,000)	(38,872,203)	(664,710,421)
Future production taxes	(97,457,261)	(50,235,000)	(7,410,909)	(155,103,170)
Future net cash flows	970,980,933	507,448,000	65,678,185	1,544,107,118
10% discount to reflect timing of cash flows	(627,533,692)	(305,160,000)	(47,669,824)	(980,363,516)
Standardized measure of discounted future net cash flows	$ 343,447,241	$ 202,288,000	$ 18,008,361	$ 563,743,602

The primary changes in the pro forma standardized measure of discounted estimated future net cash flows were as follows for 2011:

	Year Ended December 31, 2011			
	Windsor Permian Historical	Gulfport Contribution Historical	Windsor UT Historical	Total Pro Forma
Sales and transfers of oil and gas produced, net of production costs	$ (34,299,766)	$ (16,292,000)	$ (410,826)	$ (51,002,592)
Net changes in prices and production costs and development costs	86,655,407	48,089,000	383,765	135,128,172
Extension and discoveries	69,375,680	29,432,000	4,195,434	103,003,114
Revisions of previous quantity estimates, less related production costs	(100,433,225)	(71,088,000)	1,899,993	(169,621,232)
Accretion of discount	33,035,782	16,211,000	864,314	50,111,096
Change in production rates and other	(41,244,457)	33,830,000	2,432,541	(4,981,916)
Total change in standardized measure of discounted future net cash flows	$ 13,089,421	$ 40,182,000	$ 9,365,221	$ 62,636,642

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MANAGEMENT S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the Selected Historical Consolidated Financial Data and the combined financial statements and related notes included elsewhere in this prospectus. This discussion contains forward-looking statements reflecting our current expectations and estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in the sections entitled Risk Factors and Cautionary Note Regarding Forward-Looking Statements appearing elsewhere in this prospectus.

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. 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.

We intend to increase stockholder value by profitably growing reserves and production, primarily through drilling operations. We seek high quality exploration and development projects with potential for providing long-term drilling inventories that generate high returns. Substantially all of our revenues are generated through the sale of oil, natural gas liquids and natural gas production. For the year ended December 31, 2011, our production was approximately 74% oil, 15% natural gas liquids and 11% natural gas.

We began operations in December 2007 with our acquisition of certain strategic oil and gas properties located in the Permian Basin of West Texas from ExL Petroleum, LP, Ambrose Energy I, Ltd. and certain other sellers for approximately $85.0 million. Through this transaction, we acquired 4,174 net acres with production at the time of acquisition of approximately 800 net barrels of oil equivalent, or BOE/d, from 33 gross (16.5 net) wells. Subsequently, we acquired approximately 25,851 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 30,025 net acres at March 31, 2012 and, after giving effect to the Contributions, we had 49,703 net acres in the Permian Basin. Since our initial acquisition in the Permian Basin through March 31, 2012, we drilled or participated in the drilling of 152 gross (81 net) wells (or 158 gross (141 net) wells after giving effect to the Contributions) on our acreage in this area, primarily targeting the Wolfberry play. We are the operator of approximately 99% of our Permian Basin acreage.

We have increased our initial leasehold position through the following acquisitions in the Wolfberry play for an aggregate net cost of $41.2 million.

- In 2008, we acquired 6,247 net acres at the Spanish Trail and Munn prospects in Midland County, Texas through 11 leases and one mineral deed, with 5,146 net acres attributable to one lease;

- Commencing in 2008 and ending in 2010, we acquired leases at the Barron prospect in Midland County, Texas covering 225 net acres;

- Commencing in 2008 and ending in 2011, we acquired leases at the Gist prospect in Ector County, Texas covering 1,404 net acres;

- In 2008, 2009 and 2011, we acquired 35 leases at the UL prospect in Andrews and Upton Counties, Texas covering a total of 9,966 net acres;

- Beginning in 2008, we acquired 17 leases at the Hurt/WHL prospect in Ector County, Texas covering 2,779 net acres;

In 2009, we acquired one lease at the Cumberland prospect located in Midland County, Texas covering 207 net acres;

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- In 2010, we acquired leases at the North Howard prospect located in Howard County, Texas that currently cover 176 net acres;

- In 2010, we acquired 912 net acres at the Sabo prospect in Upton County, Texas;

- In 2010 and 2011, we acquired 150 leases at the Big Max prospect located in Andrews County, Texas covering 825 net acres; and

- In 2011, we acquired three leases in the Clete prospect in Crockett County, Texas covering 3,110 net acres.

Diamondback Energy, Inc. was incorporated in Delaware on December 30, 2011 as a holding company and will not conduct any material business operations prior to the transaction described below. Our historical financial information included in this prospectus pertains to assets, liabilities, revenues and expenses of Windsor Permian LLC, which is an entity controlled by our equity sponsor, Wexford. Prior to the closing of this offering, Wexford will cause DB Holdings, an entity controlled by Wexford, to contribute all of the outstanding equity interests in Windsor Permian LLC to us in exchange for shares of our common stock, and Windsor Permian LLC will become our wholly-owned subsidiary. In addition, Wexford has agreed to cause all the outstanding equity interests in Windsor UT to be contributed to Windsor Permian prior to the time Windsor Permian is contributed to us. Contemporaneously with the contribution of Windsor Permian to us, Gulfport will complete the Gulfport contribution in exchange for shares of our common stock.

Prior to Windsor Permian being contributed to us, Windsor Permian will distribute to its sole member its minority equity interests in Bison Drilling and Field Services LLC, or Bison, and Muskie Holdings LLC, or Muskie. Bison was formed in November 2010 as a wholly-owned subsidiary of Windsor Permian. Between March 2011 and April 2012, Gulfport and various entities controlled by Wexford acquired interests in Bison, which reduced Windsor Permian s interest to approximately 22%. Bison owns and operates four drilling rigs and various oil and natural gas well servicing equipment and has performed drilling and field services for us. Muskie was formed in October 2011 when Windsor Permian contributed certain assets, real estate and rights in a lease covering land in Wisconsin to Muskie in exchange for a 48.6% equity interest. The contributed lease is prospective for oil and natural gas fracture grade sand. At the time of the contribution, the remaining interests in Muskie were held by Gulfport and entities controlled by Wexford. Through additional contributions from the Wexford-controlled entities, Windsor Permian s equity interest in Muskie decreased to approximately 33%. Windsor Permian s interests in Bison and Muskie will be distributed to Windsor Permian s sole member prior to the contribution of Windsor Permian to us so we may focus our activities on our oil and natural gas exploration and development activities. We recorded revenues attributable to Bison in our consolidated statements of operations of $0.8 million during 2010 and $1.5 million during the first quarter of 2011, at which time Bison was deconsolidated for financial reporting purposes. Muskie was formed in 2011, and we recorded a loss from equity method investments of $7,107 million for 2011. The interests in Bison and Muskie are reflected in Investments-equity method on our consolidated balance sheets. For additional information regarding Bison and Muskie, see *Unaudited Pro Forma Condensed Consolidated Financial Statements* and *Related Party Transactions* beginning on pages 48 and 118, respectively, of this prospectus and Note 5 to our consolidated financial statements appearing elsewhere in this prospectus.

Since we began operations, 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.

Like all oil and natural gas exploration and production companies, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well naturally decreases. Thus, an oil and natural gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on managing costs associated with drilling and the development and production of reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. We expect the permitting and approval process to become more difficult with increased activism from environmental and other groups which may extend the time it takes us to receive permits. Because of our relatively small size and concentrated property base, we can be disproportionately disadvantaged by delays in obtaining or failing to obtain drilling approvals compared to companies with larger or more dispersed property bases. As a result, we are less able to shift drilling activities to areas where permitting may be easier and we have fewer properties over which to spread the costs related to complying with these regulations and the costs or foregone opportunities resulting from delays.

Reserves and pricing

In December 2008, the SEC released the final rule for Modernization of Oil and Gas Reporting. Among other changes, the final rule requires us to report oil and natural gas reserves and calculate the full cost ceiling value using the unweighted arithmetic average first-day-of-the-month oil and natural gas prices during the 12-month period ending in the reporting period. The prior SEC rule required using prices at period end. The requirements of this standard became effective for the year ended December 31, 2009. These revisions and requirements affect the comparability between reporting periods prior to and after the year ended December 31, 2009 for reserve volume and value estimates, full cost pool write-down calculations and the calculations of depletion of oil and gas assets.

In the table below, Ryder Scott estimated all of our proved reserves at December 31, 2011 and Pinnacle estimated all of our proved reserves at December 31, 2010 and 2009. 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.

	2011	2010	2009
Estimated Net Proved Reserves:			
Oil (Bbls)	16,716,867	18,819,050	29,230,940
Natural gas (Mcf)	19,618,865	21,662,720	27,481,820
Natural gas liquids (Bbls)	4,763,274	5,563,978	7,522,225
Total (BOE)	24,749,952	27,993,481	41,333,468

	2011	2010	2009
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (Bbls)	$ 93.09	$ 77.61	$ 58.84
Natural gas (Mcf)	$ 3.91	$ 4.14	$ 3.64
Natural gas liquids (Bbls)	$ 56.33	$ 40.74	$ 29.37

Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations, and additional changes in commodity prices may significantly affect the economic viability of drilling projects, as well as the economic valuation and economic recovery of oil and gas reserves.

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 year ended December 31, 2011, our revenues were derived 84% from oil sales, 10% from natural gas liquids sales, 3% from natural gas sales and 3% 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. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per 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 $1.83 per MMBtu in September 2009 to a high of $15.52 per MMBtu in January 2006. During 2011, West Texas Intermediate prices ranged from $75.67 to $113.93 per Bbl for oil and wellhead natural gas market prices ranged from $2.79 to $4.92 per Mcf. On March 31, 2012, the West Texas Intermediate posted price for crude oil was $103.02 per Bbl and the Henry Hub spot market price of natural gas was $2.02 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 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.

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. We calculate depreciation on the cost of fixed assets related to other fixed assets.

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.

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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.

Loss on derivative contracts. 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. As of December 31, 2011, we were a limited liability company treated as a disregarded entity for federal income tax purposes. Accordingly, no provision for federal or state corporate income taxes has been provided for the year ended December 31, 2011 or prior fiscal years because taxable income is allocated directly to our equity holders. Prior to the completion of this offering, Windsor Permian will become our wholly-owned subsidiary and, because we are a subchapter C corporation under the Internal Revenue Code, the earnings at Windsor Permian will become subject to federal and state entity-level taxation. We will establish a net deferred tax liability for differences between the tax and book basis of our assets and liabilities, and we will record a corresponding first day tax expense to net income from continuing operations. On a pro forma basis, at December 31, 2011 the amount of this charge would have been $26.2 million. It is anticipated that the company will be subject to a future, total combined federal and state income tax rate of 34% to 36%.

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Results of Operations

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

	Year Ended December 31,		
	2011	**2010**	**2009**
Operating Results:			
Revenues			
Oil and natural gas revenues	$ 47,180,802	$ 26,441,927	$ 12,716,011
Other income	1,490,910	811,247	
Operating expenses			
Lease operating expense	10,345,355	4,588,559	2,366,623
Production taxes	2,333,853	1,346,879	663,068
Gathering and transportation expense	201,828	105,870	42,091
Oil and natural gas services	1,732,892	811,247	
Depreciation, depletion and amortization	15,402,826	8,145,143	3,215,891
General and administrative	3,603,479	3,051,627	5,062,618
Asset retirement obligation accretion expense	63,259	37,856	27,934
Total expenses	33,683,492	18,087,181	11,378,225
Income from operations	14,988,220	9,165,993	1,337,786
Net interest income (expense)	(2,516,861)	(801,791)	24,137
Loss on derivative contracts	(13,009,393)	(147,983)	(4,068,005)
Loss from equity investment	(7,017)		
Net income (loss)	$ (545,051)	$ 8,216,219	$ (2,706,082)
Production Data:			
Oil (Bbls)	441,822	280,721	168,741
Natural gas (Mcf)	413,640	323,847	253,321
Natural gas liquids (Bbl)	86,815	79,978	70,384
Combined volumes (BOE)	597,577	414,674	281,345
Daily combined volumes (BOE/d)	1,637	1,136	771
Average Prices(1):			
Oil (per Bbl)	$ 92.26	$ 76.51	$ 58.01
Natural gas (per Mcf)	3.98	4.32	3.64
Natural gas liquids (per Bbl)	54.98	44.56	28.49
Combined (per BOE)	78.95	63.77	45.20
Average Costs (per BOE):			
Lease operating expense	$ 17.31	$ 11.07	$ 8.41
Gathering and transportation expense	0.34	0.26	0.15
Production taxes	3.91	3.25	2.36
Production taxes as a % of sales	4.9%	5.1%	5.2%
Depreciation, depletion and amortization	25.78	19.64	11.43
General and administrative	6.03	7.36	17.99

(1) After giving effect to our hedging arrangements in effect during 2009, the average prices per Bbl of oil and per BOE (on a combined basis), were $41.59 and $35.35, respectively, during that year. Average prices for our hydrocarbons were not impacted by our hedging arrangements during 2011 or 2010.

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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 $20.8 million, or 78%, to $47.2 million for the year ended December 31, 2011 from $26.4 million 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 501 BOE/d during the year ended December 31, 2011 as compared to the same period in 2010. The total increase in revenue of approximately $20.8 million 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 161,101 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 $7.7 million (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 $13.0 million (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 at December 31, 2011(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 15.75	441,822	$ 6,959
Natural gas liquids	$ 10.42	86,815	$ 905
Natural gas	$ (0.34)	413,640	$ (141)
Total revenues due to change in price			$ 7,723

	Change in production volumes(1)	Prices at December 31, 2010(2)	Total net dollar effect of change (in thousands)
Effect of changes in volumes:			
Oil	161,101	$ 76.51	$ 12,326
Natural gas liquids	6,837	$ 44.56	$ 305
Natural gas	89,793	$ 4.32	$ 388
Total revenues due to change in volumes			$ 13,019
Total change in revenues			$ 20,742

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

(2) Prices represent the unweighted arithmetic average first-day-of-the-month oil and natural gas prices during the 12-month period ended December 31, 2010.

Lease Operating Expense. Lease operating expense was $10.3 million ($17.31 per BOE) for the year ended December 31, 2011, an increase of $5.7 million, or 125%, from $4.6 million ($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. The processing cost of approximately $200,000 per month has been necessary to meet pipeline specifications.

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During the second quarter of 2012, we intend to complete 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 reduce water trucking, respectively. We believe that our reduced well failure rate and the completion of the gathering systems will help reduce our lease operating expense on a per-BOE basis in future periods.

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 $1.0 million, or 73.3%, from $1.3 million during the year ended December 31, 2010 to $2.3 million 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 $7.3 million, or 89.1%, from $8.1 million for the year ended December 31, 2010 to $15.4 million for the year ended December 31, 2011. The weighted average depletion rate was $25.40 per BOE for the year ended December 31, 2011 and $17.78 per BOE for the year ended December 31, 2010. The depletion rate increase was due primarily to an increase in costs and a decrease in proved reserves at December 31, 2011 for the reasons described in *Business Oil and Gas Data* beginning on page 84 of this prospectus.

General and Administrative Expense. General and administrative expense increased $0.5 million from $3.1 million for the year ended December 31, 2010 to $3.6 million for the year ended December 31, 2011. A $1.9 million increase primarily attributable to salary and equity based compensation expense for our new executive team was partially offset by the capitalization of $0.9 million of such expense and a $0.5 million increase in COPAS overhead payments due to increased drilling activity.

Interest Expense. Interest expense for the year ended December 31, 2011 was $2.5 million, as compared to $0.8 million for the year ended December 31, 2010, an increase of $1.7 million. Our weighted average outstanding principal under our credit agreement was $69.0 million for the year ended December 31, 2011 as compared to $23.0 million for 2010 due to our increased drilling activity.

Hedging Activities. We have used price swap derivatives to reduce price volatility associated with certain of our oil sales. In these swaps, we received the fixed price per the contract and paid 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 our derivative contracts as of December 31, 2011 are Hess Corporation, or Hess, and BNP Paribas, or BNP, which we believe are acceptable credit risks.

All derivative financial instruments are recorded on our consolidated balance sheets 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.

On October 4, 2011, in an effort to lock-in prices on our anticipated base level of production, while at the same time providing downside protection for our borrowing base, we entered into West Texas Intermediate light sweet crude oil swaps on the NYMEX with BNP for the calendar years 2012 and 2013 of 1,000 barrels per day priced at $78.50 and $80.55, respectively.

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Set forth below are the summarized amounts, terms and fair values of outstanding instruments held as of December 31, 2011. As of December 31, 2011, we had unrealized losses under all of our crude oil swaps. We may seek to settle some or all of these swaps after the closing of this offering with a portion of the net proceeds depending upon our assessment of market conditions.

Description and Production Period **Crude Oil Swaps:**	Volume (Bbls)	Original Strike Price (per Bbl)	December 31, 2011 Fair Value Liability
January November 2012	335,000	$ 78.50	$ 6,833,265
December 2012	31,000	78.50	594,223
January December 2013	365,000	80.55	5,544,350

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.

In December 2007, we entered into a swap contract covering 1,680,000 Bbls of oil for the period from January 2008 through 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 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 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, 2011 and December 31, 2010.

Description and Production Period				December 31,	
		Original Strike Price	Lock-in Price	2011	2010
Oil Swaps:	Volume (Bbls)	(per Bbl)	(per Bbl)	Fair Value Liability	Fair Value Liability
December 2010	22,000	$ 82.80	$ 99.45-103.20	$	$ 392,462
January November 2011	180,000	82.90	98.50 102.20		4,159,695
December 2011	90,000	82.90	98.50 102.20	378,750	377,314
January December 2012	270,000	85.07	98.25 101.80	3,876,959	3,844,101

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, 2011 and December 31, 2010.

Description and Production Period				December 31,	
		Original Strike Price	Lock-in Price	2011 Fair	2010 Fair
Oil Swaps:	Volume (Bbls)	(per Bbl)	(per Bbl)	Value Asset	Value Asset
December 2010	8,000	$ 82.80	75.00	$	$ 62,400
January November 2011	82,500	82.90	78.42		369,205
December 2011	7,500	82.90	78.42	33,600	33,503
January December 2012	90,000	85.07	80.52	409,380	406,489

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

	Years Ended December 31,		
	2011	2010	2009
Unrealized loss on open non-hedge derivative instruments	$ 12,971,838	$	$
Unrealized loss on locked-in non-hedge derivative instruments			1,297,979
Loss on settlement of non-hedge derivative instruments	37,555	147,983	2,770,026
Loss on derivative contracts	$ 13,009,393	$ 147,983	$ 4,068,005

We are required to provide margin deposits whenever our unrealized losses with Hess exceed predetermined credit limits. We had a margin deposit held by Hess of $2.3 million and $6.5 million as of December 31, 2011 and 2010, respectively, which earns interest that is remitted to us. Under our master netting agreement with Hess, we have offset this margin deposit against its derivative positions.

Year ended December 31, 2010 Compared to Year ended December 31, 2009

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $13.7 million, or 108%, to $26.4 million during the year ended December 31, 2010 from $12.7 million for the year ended December 31, 2009. 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 365 BOE/d during the year ended December 31, 2010 as compared to the year ended December 31, 2009. The total increase in revenue of approximately $13.7 million is largely attributable to higher oil, natural gas liquid and natural gas production volumes as well as an increase in oil, natural gas liquid and natural gas prices realized for the year ended December 31, 2010 as compared to year ended December 31, 2009. Production increased by 111,980 Bbls of oil, 9,594 Bbls of natural gas liquids and 70,526 Mcf of natural gas during 2010 as compared to 2009. The net dollar effect of the increase in prices of approximately $6.7 million (calculated as the change in year-to-year average prices times current year production volumes for oil, natural gas liquids and natural gas) and the net dollar effect of the change in production of approximately $7.0 million (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 at December 31, 2010[1]	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 18.50	280,721	$ 5,193
Natural gas liquids	$ 16.07	79,978	$ 1,285
Natural gas	$ 0.68	323,847	$ 220
Total revenues due to change in price			$ 6,698

	Change in production volumes[1]	Prices at December 31, 2009	Total net dollar effect of change (in thousands)
Effect of changes in volumes:			
Oil	111,980	$ 58.01	$ 6,496
Natural gas liquids	9,594	$ 28.49	$ 273
Natural gas	70,526	$ 3.64	$ 257
Total revenues due to change in volumes			$ 7,026
Total change in revenues			$ 13,724

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

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Lease Operating Expense. Lease operating expense was $4.6 million ($11.07 per BOE) for the year ended December 31, 2010, an increase of $2.2 million, or 92%, from $2.4 million ($8.41 per BOE) for the year ended December 31, 2009. The increase is due to increased drilling activity, which resulted in additional producing wells in 2010 as compared to 2009. On a per-BOE basis, the increase is due to cost increases in services and supplies, primarily as a result of the increased demand for such services and supplies in the Permian Basin, and increased commodity prices as well as additional well failure repairs coupled with downtime associated with the failures impacting production.

Production Tax Expense. Production taxes as a percentage of oil and natural gas sales were 5.1% for the year ended December 31, 2010 as compared to 5.2% for the year ended December 31, 2009. 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 $0.6 million, or 86%, from $0.7 million for the year ended December 31, 2009 to $1.3 million for the year ended December 31, 2010 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 $4.9 million, or 153%, from $3.2 million for the year ended December 31, 2009 to $8.1 million for the year ended December 31, 2010. The weighted average depletion rate was $11.21 per BOE in 2009 and $17.78 per BOE in 2010. The higher depletion rate in 2010 was due primarily to downward reserve revisions due to undeveloped locations being scheduled for development beyond five years and thus being excluded from proved reserves.

On December 31, 2009, we adopted the new SEC rules related to disclosures of oil and natural gas reserves. As a result of these new SEC rules, we recorded additional proved reserves and utilized the additional proved reserves in our depletion computation for 2009. Our 2009 depletion expense rate was $11.21 per BOE, which is lower in part due to these additional proved reserves.

General and Administrative Expense. General and administrative expense decreased $2.0 million, or 39%, from $5.1 million for the year ended December 31, 2009 to $3.1 million for the year ended December 31, 2010. This decrease was primarily due to a reduction in our labor force. As our capital expenditure programs result in increased production levels, we expect that general and administrative expense per unit of production will continue to decrease.

Interest Expense. Interest expense for 2010 was $0.8 million as compared to an interest expense of $0.01 million for 2009. During the year ended December 31, 2010, $0.2 million of our interest was capitalized and our weighted average outstanding principal under our credit agreement was $23.0 million, which was used primarily to fund our increased drilling program. During the year ended December 31, 2009, most of the interest was capitalized and our weighted average outstanding principal was $6.7 million.

Hedging Activities. We have used price swap derivatives to reduce price volatility associated with certain of our oil sales. In these swaps, we received the fixed price per the contract and paid 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 counterparty to all of our derivative contracts is Hess, which we believe is an acceptable credit risk.

All derivative financial instruments are recorded on our consolidated balance sheets 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.

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.

In December 2007, we entered into a swap contract covering 1,680,000 Bbls of oil for the period from January 2008 through 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 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 oil swaps. We have not entered into any new swap contracts since the initial contract in December 2007. As of December 31, 2010 and 2009, all swap contracts were locked-in with counter 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, 2010 and 2009.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	December 31, 2010 Fair Value Liability	December 31, 2009 Fair Value Liability
Oil Swaps:					
December 2009	22,000	$ 83.75	$ 102.25 105.90	$	$ 432,550
January November 2010	242,000	82.80	99.45 103.20		4,312,111
December 2010	22,000	82.80	99.45 103.20	392,462	390,714
January December 2011	270,000	82.90	98.50 102.20	4,537,009	4,485,047
January December 2012	270,000	85.07	98.25 101.80	3,844,101	3,737,855

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, 2010 and 2009.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	December 31, 2010 Fair Value Asset	December 31, 2009 Fair Value Asset
Oil Swaps:					
December 2009	8,000	$ 83.75	$ 71.03	$	$ 101,757
January November 2010	88,000	82.80	75.00		685,405
December 2010	8,000	82.80	75.00	62,400	62,108
January December 2011	90,000	82.90	78.42	402,708	397,880
January December 2012	90,000	85.07	80.52	406,489	394,696

None of our 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 contracts included in the consolidated statements of operations as follows:

	Years ended December 31, 2010	2009
Unrealized loss on locked-in non-hedge derivative instruments	$	$ 1,297,979
Loss on settlement of non-hedge derivative instruments	147,983	2,770,026
Loss on derivative contracts	$ 147,983	$ 4,068,005

We are required to provide margin deposits whenever our unrealized losses with Hess exceed predetermined credit limits. We had a margin deposit held by Hess of $6.5 million and $10.3 million as of December 31, 2010 and 2009, respectively. Interest earned on the deposit is remitted to us. As we have a master netting agreement with Hess, we have offset this margin deposit against derivative positions.

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Liquidity and Capital Resources

Our primary sources of liquidity to date have been capital contributions from our equity holder, borrowings under our credit facility and cash flows from operations. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. We regularly evaluate potential capital sources, including equity and debt financings, in an effort to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

Liquidity and cash flow

Our cash flows for the years ended December 31, 2011, 2010 and 2009 are presented below:

	Year Ended December 31,		
	2011	2010	2009
Net cash provided by operating activities	$ 30,384,194	$ 5,175,824	$ 2,701,566
Net cash used in investing activities	(76,314,042)	(53,134,641)	(32,149,617)
Net cash provided by financing activities	48,642,492	49,618,254	23,849,250
Net change in cash	$ 2,712,644	$ 1,659,437	$ (5,598,801)

Operating Activities

Net cash provided by operating activities was $30.4 million for the year ended December 31, 2011 as compared to $5.2 million 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* on page 59. The increase in production is largely a result of our increased drilling activities throughout 2011.

Net cash provided by operating activities was $5.2 million for the year ended December 31, 2010 as compared to $2.7 million for the year ended December 31, 2009. 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* on page 59. The increase in production volumes is largely a result of our increased drilling program in 2010. The increase in operating activities was partially offset by changes in our working capital components in 2010 which consisted primarily of the purchase of inventory of tubular goods for our drilling program and increased accounts receivables due to the increase in our drilling activities in 2010.

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 $76.3 million, $53.1 million and $32.1 million during the years ended December 31, 2011, 2010 and 2009, respectively.

During 2011, we spent $72.2 million on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 54 gross (31 net) wells. We spent an additional $3.2 million on leasehold costs, $4.1 million for the purchase of certain assets, real estate and leasehold interests which were subsequently contributed to Muskie and $2.9 million for the purchase of drilling rigs and other equipment which were subsequently contributed to Bison. These amounts were partially offset by proceeds of $6.0 million from a partial sale of our equity investment, $0.05 million from the sale of property and equipment and $0.08 million from the settlement of non-hedge derivative investments and margin deposits.

During 2010, we spent $39.0 million on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 40 gross (25 net) wells. We spent an additional $3.5 million for the purchase and development of leasehold interests, $11.7 million for the purchase of drilling rigs, well servicing equipment and other equipment which were subsequently contributed to Bison and $0.2 million for the settlement of non-hedge derivative instruments and margin deposits. These amounts were partially offset by the $1.3 million we received from the sale of approximately 10,946 net acres of non producing acreage in the Permian Basin.

During 2009, we spent $24.0 million on capital expenditures in conjunction with our drilling program in which we participated in the drilling of 12 gross (nine net) wells. We spent an additional $2.7 million for the purchase and development of leasehold interests in the Permian Basin and $5.5 million for the net amount of the settlement of non-hedge derivative instruments and margin deposits.

Our investment activities for the years ended December 31, 2011, 2010 and 2009 are summarized in the following table:

	Year Ended December 31,		
	2011	**2010**	**2009**
Drilling and completion of wells	$ (72,165,677)	$ (38,979,629)	$ (23,955,667)
Proceeds from leasehold acquisitions	(3,213,932)	(3,493,464)	(2,667,068)
Purchase of other property and equipment	(7,064,972)	(11,741,073)	(8,856)
Proceeds from sale of property and equipment	54,909	1,270,075	2,000
Settlement of non-hedge derivative instruments	(4,126,800)	(3,962,440)	(2,770,026)
Receipt (payment) on derivative margins	4,202,467	3,771,890	(2,750,000)
Proceeds from equity investment, net	5,999,963		
Net cash used in investing activities	$ (76,314,042)	$ (53,134,641)	$ (32,149,617)

Financing Activities

Net cash provided by financing activities for 2011 was $48.6 million as compared to $49.6 million for 2010. During 2011, we borrowed $40.2 million under our revolving credit facility and received capital contributions from entities controlled by Wexford, our equity sponsor, of $9.2 million. These proceeds were used primarily to fund our drilling costs and purchase property and equipment.

Net cash provided by financing activities for 2010 was $49.6 million as compared to $23.8 million for 2009. The net cash provided by financing activities in 2010 is primarily attributable to borrowings of $61.1 million under our revolving credit facility, partially offset by principal payments of $24.0 million under our prior credit facility with the Bank of Oklahoma, N.A. During 2010, we received capital contributions from entities controlled by Wexford, our equity sponsor, of $18.8 million which were partially offset by distributions to Wexford of $5.6 million. We paid $0.7 million 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.

Net cash provided by financing activities for 2009 was $23.8 million as compared to $80.2 million for 2008. The net cash provided by financing activities in 2009 is attributable to borrowings of $7.7 million under our

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revolving credit facility and $16.9 million of capital contributions from entities controlled by Wexford, our equity sponsor, which amounts were partially offset by distributions to Wexford of $0.6 million. We paid $0.1 million for debt issuance costs and costs relating to the preparation for the initial public offering. We used the net proceeds from our financing activities to fund our drilling program, the purchase of property and equipment, the acquisition and development of leasehold and the settlement of our non-hedge derivative instruments.

Existing Revolving Credit Facility

On October 15, 2010, we entered into a senior secured revolving credit agreement with BNP Paribas, or BNP, as administrative agent for the several lenders, providing for a $100.0 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 outstanding borrowings bear interest at a rate elected by us that is currently 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 is payable voluntarily or 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 14, 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 between scheduled redeterminations. 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. Under the terms of the revolving credit agreement as currently in effect, the borrowing base will remain at $100.0 million through October 15, 2012, at which time the borrowing base will be reduced to $85.0 million, subject to the periodic and elective borrowing base redeterminations described above. However, we expect that our borrowing base will be increased as a result of our acquisition of the oil and gas properties subject to the Gulfport contribution and those properties owned by Windsor UT. As of December 31, 2011, we had outstanding borrowings of $85.0 million, which bore interest at a weighted average rate of 3.3%.

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.

Financial Covenant	**Required Ratio**
Ratio of EBITDAX to interest expense(1)	Not less than 2.5 to 1.0
Ratio of total debt to EBITDAX	Not greater than 3.5 to 1.0
Ratio of current assets to liabilities	Not less than 1.0 to 1.0

(1) 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 in such period: interest, income taxes, depreciation, depletion, amortization, exploration expenses, extraordinary items and other similar noncash charges, minus all noncash income added to our consolidated net income.

As of December 31, 2011, 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 cure period. For payments of interest under our revolving credit facility, we have a three business day grace period, and a 30-day cure period for most covenant defaults, except for defaults of certain covenants, including the financial covenants and negative covenants under our revolving credit facility.

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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.

Capital Requirements and Sources of Liquidity

We currently anticipate our 2012 capital budget for drilling and infrastructure will be approximately $180.0 million after giving effect to the Contributions. We intend to allocate these expenditures as follows:

- $158.0 million for the drilling and completion of operated wells;
- $8.0 million for our participation in the drilling and completion of non-operated wells;
- $8.0 million for leasehold acquisitions; and
- $6.0 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 2012 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 2012, we believe that our cash flow from operations, proceeds of this offering and borrowings under our revolving credit facility will be sufficient to fund our operations for at least the next 12 months. 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. We cannot assure you that operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our capital expenditure budget for 2012 does not allocate funds to any leasehold interest and property acquisitions. In the event we make one or more acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we seek additional capital for that or other reasons, we may do so through traditional reserve base borrowings, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. We cannot assure you that needed capital will

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be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, 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 and Commercial Commitments

The following table summarizes our contractual obligations and commercial commitments as of December 31, 2011:

	Payments Due By Year				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
	(in thousands)				
Long term debt[1]	$	$ 85,000	$	$	$ 85,000
Derivative contracts	8,320	6,139			14,459
Asset retirement obligation[2]				1,080	1,080
Operating leases	219	690	358		1,267
Total	$ 8,539	$ 91,829	$ 358	$ 1,080	$ 101,806

(1) Consists of the outstanding principal amount at December 31, 2011 under our revolving credit facility. This table does not include future commitment fees, 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. All borrowings under our revolving credit facility are due on October 14, 2014.

(2) 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. Please read Note 4 to our audited financial statements.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our 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 2 of the notes to our consolidated financial statements appearing elsewhere in this prospectus for a discussion of additional accounting policies and estimates made by management.

Use of Estimates

Certain amounts included in or affecting our 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 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 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 reserve quantities and related estimates of the present value of future net revenues, the carrying value of oil and gas properties and asset retirement obligations.

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. General and administrative 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 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 based on 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 a quarterly 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. The inclusion of our unevaluated costs into the amortization base is expected to be completed within three years.

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, 2011, 2010 and 2009. 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, effective December 31, 2009, 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

ASC Topic 410 requires companies to record a liability relating to the retirement and removal of assets used in their businesses. 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. For oil and gas properties, this is the period in which the well is drilled or acquired. The asset retirement obligation represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized cost is depreciated on the unit-of-production method.

We determine the asset retirement obligation by calculating the present value of estimated cash flows related to the liability. Estimating the future asset retirement obligation requires management to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment is made to the related asset.

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, 2011, 2010 and 2009.

Equity-Based Compensation

During the year ended December 31, 2011, we granted to our executive officers options to acquire membership interests in our Company. Such options vest in four equal annual installments commencing on the first anniversary of the date of grant and are exercisable for five years from the date of grant. Generally, in the event more than 50% of the combined voting power of our Company is not owned by Wexford or its affiliates and there is a material change in the terms of the option holder s employment, the options will vest immediately. Summarized below are the grant dates with the total exercise prices and total fair values of the underlying options:

Months Ended	Membership Interests Granted	Exercise Price	Fair Value at Date of Grant
April 2011	1.00%	$ 3,600,000	$ 1,452,851
August 2011	1.20%	6,000,000	1,383,976
September 2011	1.25%	5,900,000	1,532,612
November 2011	0.25%	1,250,000	288,328
	3.70%	$ 16,750,000	$ 4,657,767

At December 31, 2011, for outstanding options, the intrinsic value was $112,500 and the weighted-average remaining contractual terms were 4.6 years. Also, at December 31, 2011, no options were exercisable.

We account for such options issued using a fair-value-based method calculated on the grant-date of the award. The resulting cost is 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 is 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 our expectations regarding dividends.

We do not have a history of market prices for our membership interests because such interests are not publicly traded. We utilized the observable data for a group of peer companies that grant options to assist in developing our volatility assumption. 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 terms 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. We do 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 is as follows:

	Year Ended December 31, 2011
Expected term	5 years
Risk-free interest rate	0.96%
Expected volatility	45.50%
Expected dividend yield	0.00%

As of December 31, 2011, we assumed no annual forfeiture rate because of our lack of turnover and lack of history for this type of award. We will continue to evaluate the appropriateness of the forfeiture rate based on actual forfeiture experience, analysis of employee turnover behavior and other factors. Changes in the estimated forfeiture rate can have a significant effect on reported equity-based compensation expense, because the cumulative effect of adjusting the rate for all expense amortization is recognized in the period the forfeiture estimate is changed.

We perform annual valuations to estimate our enterprise value. Our valuations consider a number of objective and subjective factors that we believe market participants would consider, including: (a) our business, financial condition, and results of operations, including related industry trends affecting our operations; (b) our forecasted operating performance and projected future cash flows; (c) the liquid or illiquid nature of our membership interest; (d) liquidation preferences, redemption rights and other rights and privileges of our membership interest; (e) market multiples of our most comparable public peers; and (f) market conditions affecting our industry.

We used the income approach to estimate our enterprise value. The income approach involves applying an appropriate risk-adjusted discount rate to projected cash flows based on forecasted revenue and costs. The valuations were based primarily on our independent engineering oil and gas reserve reports which are generally a cash flow model of the Company. There were no significant events during the year that caused us to adjust these values at the various grant dates.

There is inherent uncertainty in our forecasts and projections and, if we had made different assumptions and estimates than those described previously, the amount of our equity-based compensation expense could have been materially different.

Equity-based compensation expense recorded for the year ended December 31, 2011 was $544,290. The unrecognized equity-based compensation expense as of December 31, 2011 was $4,113,477 related to these awards which is expected to be recognized over a weight-average period of 3.6 years. No equity-based compensation expense was recorded for the years ended December 31, 2010 and 2009 as we had not historically issued equity-based compensation awards.

Recent accounting pronouncements

Fair Value

In May 2011, the FASB issued authoritative guidance which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and International Financial Reporting Standards. This new guidance changes some fair value measurement principles and disclosure requirements, but does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. The update is effective for annual periods beginning after December 15, 2011. The adoption of this update will not have a significant impact on our financial statements.

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Comprehensive Income

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, Comprehensive Income: Presentation of Comprehensive Income, which provides amendments to FASB ASC Topic 220, Comprehensive Income. The purpose of the amendments in this update is to provide a more consistent method of presenting non-owner transactions that affect an entity s equity. The amendments eliminate the option to report other comprehensive income and its components in the statement of changes in stockholders equity and require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. In December 2011, the FASB issued Accounting Standards Update 2011-12 which defers the requirement in Accounting Standards Update 2011-05 that companies present reclassification adjustments for each component of accumulated other comprehensive income in both net income and other comprehensive income on the face of the financial statements. Both amendments are effective for interim and annual periods beginning after December 15, 2011 and should be applied retrospectively. The adoption of this guidance will not have a significant impact on our financial position, results of operations or cash flow.

Internal Controls and Procedures

We are not currently required to comply with the SEC s rules implementing Section 404 of the Sarbanes Oxley Act of 2002, and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC s rules implementing Section 302 of the Sarbanes-Oxley Act of 2002, which will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. We will not be required to make our first assessment of our internal control over financial reporting under Section 404 until the year following our first annual report required to be filed with the SEC.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended 2009, 2010 and 2011. 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.

Quantitative and Qualitative Disclosure about Market Risks

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.

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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, 2011, we had a net liability derivative position of $14.5 million related to our price swap derivatives.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately $12.7 million at December 31, 2011) and receivables from the sale of our oil and natural gas production (approximately $5.0 million at December 31, 2011).

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 years ended December 31, 2011 and 2010, one purchaser, Windsor Midstream LLC, an entity controlled by Wexford, our equity sponsor, accounted for approximately 78.4% and 81.7% of our revenue, respectively. For the year ended December 31, 2009, two purchasers accounted for more than 10% of our revenue: Windsor Midstream LLC (68.3%) and DCP Midstream, LP (14.8%). 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 each of December 31, 2011 and 2010, we had one customer that represented approximately 68% and 62%, respectively, of our total joint operations receivables. Prior to 2010, we did not operate the wells and, therefore, did not have 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 with BNP. The terms of our revolving credit facility with BNP 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 3.3% as of December 31, 2011. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our net income (loss) of approximately $850,000 annually, based on the $85.0 million outstanding in the aggregate under our revolving credit facility with BNP as of December 31, 2011, and assuming no interest is capitalized. Pending use of the net proceeds from this offering to fund our exploration and development activities and for general corporate purposes, we intend to repay outstanding borrowings under our revolving credit facility with BNP.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements. Please read Note 11 to our consolidated financial statements included elsewhere in this prospectus for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

BUSINESS

General

Overview

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

We began operations in December 2007 with our acquisition of 4,174 net acres with production at the time of acquisition of approximately 800 BOE/d from 33 gross (16.5 net) wells in the Permian Basin. Subsequently, we acquired approximately 25,851 additional net acres, which brought our total net acreage position in the Permian Basin to 30,025 net acres at March 31, 2012 and, after giving effect to the Contributions, we had 49,703 net acres. We are the operator of approximately 99% of this acreage. As of March 31, 2012, after giving effect to the Contributions, we had drilled 147 gross (136 net) wells, and participated in an additional 11 gross (five net) non-operated wells, in the Permian Basin. Of these 158 gross wells, 149 were completed as producing wells and nine were in various stages of completion. In the aggregate, as of March 31, 2012, we held interests in 182 gross (166 net) producing wells in the Permian Basin.

We built our leasehold position through the following acquisitions and development activities in the Wolfberry play:

- In 2008, we acquired 6,247 net acres at the Spanish Trail and Munn prospects in Midland County, Texas through 11 leases and one mineral deed, with 5,146 net acres attributable to one lease;

- Commencing in 2008 and ending in 2010, we acquired leases at the Barron prospect in Midland County, Texas covering 225 net acres;

- Commencing in 2008 and ending in 2011, we acquired leases at the Gist prospect in Ector County, Texas covering 1,404 net acres;

- In 2008, 2009 and 2011, we acquired 35 leases at the UL prospect in Andrews and Upton Counties, Texas covering a total of 9,966 net acres;

- Beginning in 2008, we acquired 17 leases at the Hurt/WHL prospect in Ector County, Texas covering 2,779 net acres;

- In 2009, we acquired one lease at the Cumberland prospect located in Midland County, Texas covering 207 net acres;

- In 2010, we acquired leases at the North Howard prospect located in Howard County, Texas and currently cover 176 net acres;

- In 2010, we acquired 912 net acres at the Sabo prospect in Upton County, Texas;

- In 2010 and 2011, we acquired 150 leases at the Big Max prospect located in Andrews County, Texas covering 825 net acres; and

In 2011, we acquired three leases in the Clete prospect in Crockett County, Texas covering 3,110 net acres.

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.

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As of December 31, 2011, our estimated proved oil and natural gas reserves pro forma for the Contributions were 39,460 MBOE based on reserve reports prepared by Ryder Scott Company L.P., or Ryder Scott, our independent reserve engineers. Of these reserves, approximately 21.7% are classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate are from 329 gross well locations on 40-acre spacing. As of December 31, 2011, these proved reserves were approximately 67% oil, 20% natural gas liquids and 13% natural gas.

We have 977 identified potential vertical drilling locations based on our evaluation of applicable geologic and engineering data, and we have an additional 1,162 identified potential vertical drilling locations based on 20-acre downspacing. These identified potential drilling locations do not include any potential horizontal drilling locations. 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, as estimated by Ryder Scott, range from 89 MBOE to 147 MBOE per well, with an average EUR per well of 127 MBOE. Our 2012 drilling plan currently contemplates drilling 72 gross (65 net) vertical wells and nine gross (eight net) horizontal wells in the Wolfberry play. We are currently using four drilling rigs and intend to add two additional rigs later in 2012.

We believe the experience gained from our historical drilling programs and the information obtained from the results of extensive industry drilling activity in the Permian Basin have helped us reduce the risk and uncertainity associated with drilling vertical wells on our Permian Basin acreage. We intend to supplement our vertical development drilling activity with horizontal wells targeting various intervals in the Wolfberry play. Our horizontal drilling program is intended to further capture the upside potential that may exist on our properties and increase our well performance and recoveries as compared to drilling vertical wells alone.

During 2011, we assembled a new executive team and, beginning with the fourth quarter of 2011, this team assumed management control of our operations and development activities in the Permian Basin. With an average of approximately 26 years of industry experience per person, this team has extensive experience in the Permian Basin as well as other resource plays in North America, including significant experience in drilling and completing horizontal wells. Under the direction of our new executive team, the average drilling time required to reach total depth, or TD, was shortened by 25% to 15 days during the fourth quarter of 2011 from 20 days during the second quarter of 2011, reducing average drilling costs (excluding completion costs) by 8.3% from $1.2 million to $1.1 million period-to-period, while also decreasing the time from spud to spud to 23 days from 25 days. Also, during the quarter ended March 31, 2012 our average daily production, pro forma for the Contributions, was 3,280 BOE/d, an increase of 11%, or 333 BOE/d, from 2,947 BOE/d for the quarter ended December 31, 2011. This increase was due primarily to improved strategies and procedures introduced by our new executive team relating to wellbore configuration, completion, execution, fluid recovery and well pumping practices that significantly reduced the level of required well remediation and the associated loss of production. We anticipate further increases in efficiencies as our new executive team executes on our development strategies across our acreage base.

The following table provides a summary of selected operating information of our properties, pro forma for the Contributions. The information is as of March 31, 2012 except as otherwise noted.

			Identified Potential Drilling Locations(1)		2012 Budget			Estimated Net Proved Reserves at December 31, 2011		Average Daily Production
Basin	**Net Acreage**	**Average Working Interest**	**Gross**	**Net**	**Gross Wells(2)**	**Net Wells(2)**	**Capex (In millions)**	**MBOE**	**% Developed**	**(BOE/d)(3)**
Permian	49,703	86.2%	977	926	90	75	$ 180.0	39,460	24	3,378

(1) Reflects identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data. We have an additional 1,162 identified potential vertical drilling locations based on 20-acre downspacing. These identified potential drilling locations do not include any potential horizontal drilling locations. The drilling locations on which we actually drill wells will ultimately depend on the availability of capital, regulatory approvals, oil and natural gas prices, costs, actual drilling results and other factors.

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(2) Includes 81 gross (72 net) wells for which we are the operator and nine gross (three net) non-operated wells.
(3) During February 2012.

Our current exploration and development budget for our oil and natural gas properties for the year ending December 31, 2012 is approximately $180.0 million. In 2012, we plan to spend approximately $158.0 million on the drilling and completion of 72 gross (65 net) operated vertical wells and nine gross and eight net horizontal wells, $8.0 million for the drilling and completion of nine non-operated wells, $8.0 million for leasehold acquisitions and $6.0 million for the construction of infrastructure to support production, including investments in water disposal infrastructure and gathering line projects.

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 March 31, 2012, after giving effect to the Contributions, we had 977 identified potential vertical drilling locations on our acreage in the Permian Basin based on 40-acre spacing and an additional 1,162 such locations based on 20-acre downspacing. We believe the drilling of these locations will provide us with the critical subsurface data necessary to target potential horizontal horizons. Our 2012 drilling plan currently contemplates drilling 72 gross (65 net) vertical wells and nine gross (eight net) horizontal wells in the Wolfberry play. We ended 2011 with a two rig drilling program and are currently using four drilling rigs. We intend to add two additional rigs later in the year. Subject to market conditions and rig availability, we expect to operate up to eight rigs in 2013, which we expect will allow us to significantly increase our drilling program in 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 and we currently plan to drill nine gross (eight net) horizontal wells in 2012 to target these producing horizons. Our 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.

Focus on enhancing advanced drilling and completion techniques to maximize recovery. Our eight member executive team, which has an average of approximately 26 years of industry experience per person, intends to continue to seek ways to maximize hydrocarbon recovery by refining and enhancing our drilling and completion techniques. The time to reach TD for our vertical Wolfberry wells decreased from an average of 20 days during the second quarter of 2011 to an average of 15 days during the fourth quarter of 2011, resulting in a lower total well cost. Our focus on efficient drilling and completion techniques, and the resulting 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 new 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.

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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 86.2% working interest in our acreage pro forma for the Contributions 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 we believe 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. As of December 31, 2011, on a pro forma basis after giving effect to this offering and the use of the net proceeds from this offering to repay borrowing under our revolving credit facility, we would have had approximately $ million of available borrowing capacity under such facility. We expect that we will fund our capital development plans for 2012 from our operating cash flow and borrowings under our revolving credit facility. We intend to use the net proceeds from this offering to repay borrowings outstanding under our revolving credit facility pending their use to fund our capital expenditures.

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. As of April 27, 2012, the Baker Hughes Rig Count survey reported that there were 510 rigs drilling in the Permian Basin. The majority of our current properties are well positioned in the core of the Wolfberry play. We believe that our historical vertical development success will be complemented with horizontal drilling locations that could ultimately translate into an increased recovery factor on a per section basis. Our production for the year ended December 31, 2011 was approximately 74% oil, 15% natural gas liquids and 11% natural gas. As of December 31, 2011, our estimated net proved reserves were comprised of approximately 68% oil and 19% 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 oil-weighted reserves that we believe provides attractive growth and return opportunities. As of March 31, 2012, after giving effect to the Contributions, we had 977 identified potential vertical drilling locations based on 40-acre spacing and an additional 1,162 identified potential vertical drilling locations based on 20-acre downspacing. In 2012, after giving effect to the Contributions, we anticipate drilling 72 gross (65 net) vertical operated wells and nine gross (eight net) horizontal operated wells, which represent only approximately 7.4% of our identified vertical potential drilling locations at March 31, 2012. We also believe that there are multiple horizontal locations that could be drilled on our acreage. In addition, the liquids rich natural gas component of our inventory adds value with Btu content ranging from 1,243 MMBtu to 1,578 MMBtu and our March 2012 natural gas liquids yield was 125 Bbls/MMcf. In addition, we have approximately 117 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 new executive team has an average of approximately 26 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 future development plans to include horizontal drilling. 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 over 400,000 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 processees. This operating control also enables us to obtain data needed for efficient exploration of horizontal prospects.

Financial flexibility to fund expansion. Upon the completion of this offering, we will 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, 2011, on a pro forma basis after giving effect to this offering and the use of the net proceeds from this offering to repay borrowings under our revolving credit facility, we would have had approximately $ million of available borrowing capacity under our revolving credit facility. We expect that our borrowing base will be increased as a result of the Contributions.

Our Properties

Review of Exploration, Exploitation and Development Activities

The following table summarizes certain operating information of our properties, pro forma for the Contributions. The information is as of March 31, 2012 except as otherwise noted.

			Identified Potential Drilling Locations(1)		2012 Budget			Estimated Net Proved Reserves at December 31, 2011		
Basin	**Net Acreage**	**Average Working Interest**	**Gross**	**Net**	**Gross Wells(2)**	**Net Wells(2)**	**Capex (In millions)**	**MBOE**	**% Developed**	**Average Daily Production (BOE/d)(3)**
Permian	49,703	86.2%	977	926	90	75	$ 180.0	39,460	24	3,378

(1) Reflects identified potential vertical drilling locations on 40-acre spacing based on our evaluation of applicable geologic and engineering data. We have an additional 1,162 identified potential vertical drilling locations based on 20-acre downspacing. These identified potential drilling locations do not include any potential horizontal drilling locations. The drilling locations on which we actually drill wells will ultimately depend on the availability of capital, regulatory approvals, oil and natural gas prices, costs, actual drilling results and other factors.

(2) Includes 81 gross (72 net) wells for which we are the operator and nine gross (three net) non-operated wells.

(3) During February 2011.

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 25,851 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 30,025 net acres at March 31, 2012 and, after giving effect to the Contributions, we will have 49,703 net acres. Since our initial acquisition in the Permian Basin through March 31, 2012, we drilled or participated in the drilling of 152 gross (81 net) wells (or 158 gross (141 net) wells after giving effect to the Contributions) 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 approximately 15% 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 March 31, 2012, we held interests in 181 gross (165 net) producing wells.

Geology

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

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

Several shale intervals within the Wolfcamp formation are currently being evaluated for horizontal development potential, with initial drilling expected in 2012. The shales exhibit micro-darcy permeabilities, which result in relatively small drainage areas and recovery factors. Because of this, the horizontal exploitation of these reservoirs will supplement, and not replace, the 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 117 square miles of proprietary 3-D seismic data, will be used to highgrade future locations.

Ryder Scott, an independent petroleum engineering firm, has estimated that at December 31, 2011, proved reserves net to our interest in these assets were approximately 24,750 MBOE, of which 22.0% were classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate were from 293 gross well locations on 40-acre spacing. The proved reserves are generally characterized as long-lived, with predictable production profiles.

Production Status

In February 2012, net production from our Permian Basin acreage, pro forma for the Contributions, was 97,967 BOE, or an average of 3,378 BOE/d, of which 72% was oil, 16% was natural gas liquids and 12% was natural gas. From January 1, 2011 through December 31, 2011, our average daily net production from our Permian Basin acreage, pro forma for the Contributions, was 2,514 BOE/d, of which 71% was from oil, 17% was from natural gas liquids and 12% was from 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.

Recent and Future Activity

During 2011, 56 gross (32 net) wells were drilled on our Permian Basin acreage for an aggregate estimated net cost of $82.2 million. On a pro forma basis after giving effect to the Contributions, 58 gross (50 net) wells were drilled on our Permian acreage during 2011. As of December 31, 2011, we had 977 identified potential vertical drilling locations based on 40-acre spacing and an additional 1,162 identified potential vertical drilling locations based on 20-acre downspacing. We currently expect to drill an estimated 72 gross (65 net) vertical wells and nine gross (eight net) horizontal wells on our acreage in 2012. The wells are expected to be drilled to approximately 11,200 feet at an estimated average completed gross well cost of approximately $1.9 million to $2.4 million per vertical well and $6.0 million to $7.0 million per horizontal well. In this prospectus, we define identified potential drilling locations as locations specifically identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic and engineering data on 40-acre or 20-acre downspacing as indicated. The availability of local infrastructure, drilling support assets and other factors as management may deem relevant, such as easement restrictions and state and local regulations, are considered in determining such locations. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results and other factors.

Oil and Gas Data

Proved Reserves

SEC Rule-Making Activity

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

- Disclosure of unproved reserves: probable and possible reserves may be disclosed separately on a voluntary basis.

- Proved undeveloped reserve guidelines: reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

- Reserves estimation using new technologies: reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

- Reserves personnel and estimation process: additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

- Non-traditional resources: the definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

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

Evaluation and Review of Reserves

Our historical reserve estimates were prepared by Ryder Scott as of December 31, 2011 and by Pinnacle as of December 31, 2010 and 2009, in each case with respect to our assets in the Permian Basin. Reserve estimates for properties attributable to Windsor UT and the properties subject to the Gulfport contribution were prepared, in each case, by Ryder Scott as of December 31, 2011.

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 2011 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 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.

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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; and
- verification of property ownership by our land department.

The following table presents our estimated net proved oil and natural gas reserves and the present value of our reserves as of December 31, 2011, based on the reserve report prepared by Ryder Scott, and as of December 31, 2010 and 2009, based on the reserve reports 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. The following table also sets forth estimates of our net proved oil and natural gas reserves as of December 31, 2011 on a pro forma basis after giving effect to the contribution of Windsor UT to Windsor Permian and the Gulfport contribution as if they had occurred on December 31, 2011. The reserves attributable to the Windsor UT properties and the properties subject to the Gulfport contribution have been prepared by Ryder Scott. Copies of the reserve reports as of December 31, 2011 prepared by Ryder Scott with respect to our properties, the Windsor UT properties and the properties subject to the Gulfport contribution are attached to this prospectus as Appendices B, C and D. Our estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency other than the SEC in connection with this offering.

	Pro Forma Year Ended December 31, 2011	Historical Year Ended December 31, 2011	2010	2009
Estimated proved developed reserves:				
Oil (Bbls)	6,046,099	3,805,291	3,307,550	1,954,060
Natural gas (Mcf)	8,335,945	5,186,941	4,255,300	2,453,750
Natural gas liquids (Bbls)	1,969,711	1,233,319	1,105,216	591,532
Total (BOE)	9,405,134	5,903,100	5,121,983	2,954,550
Estimated proved undeveloped reserves:				
Oil (Bbls)	20,140,375	12,911,576	15,511,500	27,276,880
Natural gas (Mcf)	24,261,520	14,431,924	17,407,420	25,028,070
Natural gas liquids (Bbls)	5,876,850	3,529,955	4,458,762	6,930,693
Total (BOE)	30,054,812	18,846,852	22,871,499	38,378,918
Estimated Net Proved Reserves:				
Oil (Bbls)	26,186,474	16,716,867	18,819,050	29,230,940
Natural gas (Mcf)	32,597,465	19,618,865	21,662,720	27,481,820
Natural gas liquids (Bbls)	7,840,561	4,763,274	5,563,978	7,522,225
Total (BOE)[1]	39,459,946	24,749,952	27,993,481	41,333,468
Percent proved developed	23.8%	23.9%	18.3%	7.1%

(1) Estimates of reserves as of December 31, 2011, 2010 and 2009 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

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day of each month within the 12-month periods ended December 31, 2011, 2010 and 2009, 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 *Risk Factors* beginning on page 14 of this prospectus. We have not filed any estimates of total, proved net oil or natural gas reserves with any federal authority or agency other than the SEC.

Additional information regarding our proved reserves can be found in *Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations* and *Critical Accounting Policies and Estimates* beginning on pages 59 and 70, respectively, of this prospectus, the notes to our consolidated financial statements included elsewhere in this prospectus and the reserve reports as of December 31, 2011 included as Appendices B, C and D to this prospectus.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2011, our proved undeveloped reserves totaled 12,912 MBbls of oil, 14,432 MMcf of natural gas and 3,530 MBbls of natural gas liquids, for a total of 18,847 MBOE. On a pro forma basis after giving effect to the Contributions, at December 31, 2011 our total proved undeveloped reserves would have totaled 20,140 MBbls of oil, 24,262 MMcf of natural gas and 5,877 MBbls of natural gas liquids for a total of 30,055 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Changes in PUDs that occurred during 2011 were primarily due to:

- Additions of 6,204 MBOE attributable to extensions resulting from strategic drilling of wells by us to delineate our acreage position;
- Conversion of approximately 2,223 MBOE attributable to PUDs into proved developed reserves;
- Negative revisions of approximately 432 MBOE in PUDs due to revisions related to offset well performance;
- Exclusion of 1,447 MBOE attributable to PUD locations that were not scheduled to be drilled within the next five years; and
- Movement of 6,116 MBOE from PUD to probable reserves due to changes in booking methodology used by our new independent petroleum engineers and well performance in one prospect area. The 2011 reserve report prepared by Ryder Scott assigned PUDs only in close proximity to seasoned production. The prior reports prepared by Pinnacle utilized a methodology consistent with large resource basins where geologic risk is minimal. The methodology utilized by Pinnacle typically results in a greater number of PUD locations than the close proximity method used by Ryder Scott. There was also a shift of 2,748 MBOE from proved to probable reserves in one prospect area where existing well performance declined more quickly than originally projected. Locations in this area were moved to the probable reserve category until more production history is obtained to confirm the economic viability of the area.

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Costs incurred relating to the development of PUDs were approximately $52.8 million during 2011 and approximately $80.9 million on a pro forma basis after giving effect to the Contributions as if they had occurred on January 1, 2011. Estimated future development costs relating to the development of PUDs are projected to be approximately $99.3 million in 2012, $152.4 million in 2013, $128.2 million in 2014, $105.4 million in 2015 and $84.4 million in 2016 after giving effect to the Contributions. Since our new 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 2016.

As of December 31, 2011, 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 net production of oil, natural gas and natural gas liquids, and certain price and cost information for each of the periods indicated:

	Pro Forma Year Ended December 31, 2011	Historical Year Ended December 31,		
		2011	2010	2009
Production Data:				
Oil (Bbls)	651,433	441,822	280,721	168,741
Natural gas (Mcf)	685,640	413,640	323,847	253,321
Natural gas liquids (Bbl)	151,815	86,815	79,978	70,384
Combined volumes (BOE)	917,521	597,577	414,674	281,345
Daily combined volumes (BOE/d)	2,514	1,637	1,136	771
Average Prices[1]:				
Oil (per Bbl)	$ 92.14	$ 92.26	$ 76.51	$ 58.01
Natural gas (per Mcf)	4.01	3.98	4.32	3.64
Natural gas liquids (per Bbl)	53.72	54.98	44.56	28.49
Combined (per BOE)	77.30	78.95	63.77	45.20
Average Costs (per BOE):				
Lease operating expense	$ 17.46	$ 17.31	$ 11.07	$ 8.41
Gathering and transportation expense	0.22	0.34	0.26	0.15
Production taxes	3.97	3.91	3.25	2.36
Production taxes as a % of sales	5.1%	4.9%	5.1%	5.2%
Depreciation, depletion and amortization	29.10	25.78	19.64	11.43
General and administrative	3.97	6.03	7.36	17.99

(1) After giving effect to our hedging arrangements in effect during 2009, the average prices per Bbl of oil and per BOE (on a combined basis), were $41.59 and $35.35, respectively, during that year. Average prices for our hydrocarbons were not impacted by our hedging arrangements during 2011 or 2010.

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Productive Wells

As of March 31, 2012, we owned an average 58.2% working interest in 177 gross (103 net) productive wells. On a pro forma basis after giving effect to the Contributions, at March 31, 2012 we would have owned an average 91.3% working interest in 181 gross (165 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.

Developed and Undeveloped Acreage

The following table sets forth information as of March 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	7,600	4,255	45,080	25,770	52,680	30,025

(1) Developed acres are acres spaced or assigned to productive wells and does 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.

On a pro forma basis after giving effect to the Contributions, at March 31, 2012 our net developed, undeveloped and total acreage would have been 6,748, 42,955 and 49,703, respectively.

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 (after giving effect to the Contributions) 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.

	Remaining 2012		2013		2014		2015		2016	
Basin	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Permian	640	250	400	222	2,651	2,041	16,761	13,628	7,133	7,133

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Drilling Results

The following table sets forth information with respect to the number of wells completed during the periods indicated. 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,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	39	23	41	27	11	8
Dry						
Exploratory:						
Productive	7	4				
Dry						
Total:						
Productive	46	27	41	27	11	8
Dry						

As of December 31, 2011, we had 12 gross (6.4 net) wells in the process of drilling, completing or dewatering or shut in awaiting infrastructure that are not reflected in the above table. Since our initial acquisition in the Permian Basin through March 31, 2012, we drilled or participated in the drilling of 152 gross (81 net) wells in the Permian Basin (or 158 gross (141 net) wells after giving effect to the Contributions), of which we operate 142 gross (76 net) wells (or 147 gross (136 net) net wells after giving effect to the Contributions). Of the 158 gross wells drilled, 149 were completed as producing wells and nine are in various stages of completion.

Operations

General

We are the operator of approximately 99% of our Permian Basin acreage. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas 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. For a description of this agreement, see *Related Party Transactions Marketing Services* on page 120 of this prospectus. 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.

We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the years ended December 31, 2011 and 2010, one purchaser, Midstream, accounted for approximately 78.4% and 81.7% of our revenue, respectively. For the year ended December 31, 2009, two purchasers accounted for more than 10% of our revenue: Windsor Midstream LLC (68.3%) and DCP Midstream, LP (14.8%). No other customer accounted for more than 10% of our revenue

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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.

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.

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.

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.

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%.

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Regulation

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 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

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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 on page 95 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 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 in April 2010 and it became effective January 2011, although it does not require immediate reductions in GHG emissions. The EPA adopted the stationary source rule, also known as the Tailoring Rule, in May 2010, and it also became effective January 2011, although it remains subject of several pending lawsuits filed by industry groups. 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. More recently, 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. 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.

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 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 EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. 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, both the EPA and the House committee have 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.

In March 2011, companion bills entitled the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, first introduced in 2009, were reintroduced in the United States Senate and House of Representatives. These bills, which are currently under consideration by Congress, would repeal the exemption for hydraulic fracturing from the SDWA, which would have the effect of allowing the EPA to promulgate regulations requiring permits and implementing potential new requirements on hydraulic fracturing under the SDWA. This development could, in turn, require state regulatory agencies in states with programs delegated under the SDWA to impose additional requirements on hydraulic fracturing operations. In addition, the bills would require persons using hydraulic fracturing, such as us, to disclose the chemical constituents, but not the proprietary formulas, of their fracturing fluids to a regulatory agency, which would make the information public via the internet. Additionally, fracturing companies would be required to disclose specific chemical contents of fluids, including proprietary chemical formulas, to state authorities or to a requesting physician or nurse if deemed necessary by the physician or nurse in connection with a medical emergency.

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 includes 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 2012 and 2014.

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These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities.

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. 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 use of fracturing fluids, impacts on drinking water supplies, use of waters 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, such as the FRAC Act, 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 natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from 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 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.

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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 property (including leased oil and gas properties), general liability, operational control of certain wells, pollution, commercial auto, umbrella liability, inland marine, workers compensation and other coverage. The limits for certain of our policies are as follows:

- oil and gas lease property: $21,888,656 with a deductible ranging from $5,000 to $20,000 based on property value;
- general liability: $1,000,000 per occurrence and $2,000,000 in the aggregate with a $25,000 deductible;
- pollution: $1,000,000 per occurrence and $2,000,000 in the aggregate with a $50,000 deductible;
- umbrella liability: $5,000,000 per occurrence with $5,000,000 aggregate coverage; and
- inland marine: limit varies on a per rig basis from $3,586,000 to $7,155,000 with a $250,000 deductible per accident.

As noted above, most of our insurance coverage includes deductibles that must be met prior to recovery. Additionally, 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.

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

We have approximately 50 full time employees, including three geologists, three engineers and three land professionals, all of whom are salaried administrative or supervisory employees. Of these 50 full time employees, 31 work in our office in Midland, Texas. None of our employees are represented by labor unions or covered by any collective bargaining agreements. We also hire independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist our full time employees.

Facilities

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

Legal Proceedings

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.

MANAGEMENT

Executive Officers and Directors

Set forth below is the name, age, position and a brief account of the business experience of each of our executive officers and directors as of March 1, 2012.

Name	Age	Position
Travis D. Stice	50	Chief Executive Officer
Teresa L. Dick	42	Chief Financial Officer, Senior Vice President
Russell Pantermuehl	52	Vice President Reservoir Engineering
Paul Molnar	56	Vice President Geoscience
Michael Hollis	36	Vice President Drilling
William Franklin	57	Vice President Land
Jeff White	55	Vice President Operations
Randall J. Holder	58	Vice President, General Counsel
Steven E. West	52	Director

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

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

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

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

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

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

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

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

Steven E. West Director Mr. West has served as a director of our company since December 2011. Mr. West served as our Chief Executive Officer from January 1, 2009 to December 31, 2011. Since January 2011, Mr. West has been a partner at Wexford, focusing on Wexford s private equity energy investments. From August 2006 until December 2010, Mr. West served as senior portfolio advisor at Wexford. From August 2003 until August 2006, Mr. West was the chief financial officer of Sunterra Corporation, a former Wexford portfolio company. From December 1993 until July 2003, Mr. West held senior financial positions at Coast Asset Management and IndyMac Bank. Prior to that, Mr. West worked at First Nationwide Bank, Lehman Brothers and Peat Marwick Mitchell & Co., the predecessor of KPMG LLP. Mr. West holds a Bachelor of Science degree in

Accounting from California State University, Chico. We believe Mr. West s background in finance, accounting and private equity energy investments, as well as his executive management skills developed as part of his career with Wexford, its portfolio companies and other financial institutions qualify him to serve on our board of directors.

Our Board of Directors and Committees

Upon completion of this offering, our board of directors will consist of seven directors, at least three of whom will satisfy the independence requirements of current SEC rules and The NASDAQ Global Market listing standards. Our certificate of incorporation provides that the terms of office of the directors are one year from the time of their election until the next annual meeting of stockholders or until their successors are duly elected and qualified.

Our certificate of incorporation provides that the authorized number of directors will generally be not less than five nor more than thirteen, and the exact number of directors will be fixed from time to time exclusively by the board of directors pursuant to a resolution adopted by a majority of the whole board. In addition, our certificate of incorporation and our bylaws provide that, in general, vacancies on the board may be filled by a majority of directors in office, although less than a quorum.

Our board of directors will establish an audit committee in connection with this offering whose functions include the following:

- assist the board of directors in its oversight responsibilities regarding the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent accountant s qualifications and independence and our accounting and financial reporting processes of and the audits of our financial statements;

- prepare the report required by the SEC for inclusion in our annual proxy or information statement;

- appoint, retain, compensate, evaluate and terminate our independent accountants;

- approve audit and non-audit services to be performed by the independent accountants;

- review and approve related party transactions; and

- perform such other functions as the board of directors may from time to time assign to the audit committee.

The specific functions and responsibilities of the audit committee will be set forth in the audit committee charter. Upon completion of this offering, our audit committee will include at least one director who satisfies the independence requirements of current SEC rules and The NASDAQ Global Market listing standards. Within one year after completion of the offering, we expect that our audit committee will be composed of three members that will satisfy the independence requirements of current SEC rules and The NASDAQ Global Market listing standards. We also expect that one of the members of the audit committee will qualify as an audit committee financial expert as defined under these rules and listing standards, and the other members of our audit committee will satisfy the financial literacy standards for audit committee members under these rules and listing standards.

Pursuant to our bylaws, our board of directors may, from time to time, establish other committees to facilitate the management of our business and operations. Because we are considered to be controlled by Wexford under The NASDAQ Global Market rules, we are eligible for exemptions from provisions of these rules requiring a majority of independent directors, nominating and corporate governance and compensation committees composed entirely of independent directors and written charters addressing specified matters. We may elect to take advantage of these exemptions. In the event that we cease to be a controlled company within the meaning of these rules, we will be required to comply with these provisions after the specified transition periods.

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Although we will be eligible for an exemption from the compensation committee requirements under The NASDAQ Global Market rules, we intend to establish a compensation committee composed of at least two independent directors in connection with this offering. See *Executive Compensation Compensation Discussion and Analysis Compensation Policy* on page 105 of this prospectus.

In connection with the Gulfport contribution, Gulfport will have the right to designate one individual as a nominee to serve on our board of directors for so long as Gulfport beneficially owns more than 10% of our outstanding common stock. Such nominee, if elected to our board, will also serve on each committee of the board so long as he or she satisfies the independence and other requirements for service on the applicable committee. So long as Gulfport has the right to designate a nominee to our board and there is no Gulfport nominee actually serving as a director, Gulfport shall have the right to appoint one individual as an advisor to the board who shall be entitled to attend board and committee meetings.

Director Compensation

To date, none of our directors has received compensation for services rendered as a board member. Members of our board of directors who are also officers or employees of our company will not receive compensation for their services as directors. It is anticipated that after the completion of this offering, we will pay our non-employee directors a monthly retainer of $ and a per meeting attendance fee of $ and reimburse all ordinary and necessary expenses incurred in the conduct of our business.

In connection with this offering, we intend to implement an equity incentive plan. Under the plan, certain non-employee directors will be granted restricted stock units, which will vest in three equal annual installments beginning on the date of grant.

Compensation Committee Interlocks and Insider Participation

We do not currently have a compensation committee. None of our executive officers serves, or has served during the past year, as a member of the board of directors or compensation committee of any other company that has one or more executive officers serving as a member of our board of directors or compensation committee.

Executive Compensation

Compensation Discussion and Analysis

Compensation Practices

Historically, our equity sponsor, Wexford, determined our overall compensation philosophy and set the compensation of our named executive officers, after taking into consideration recommendations of our then serving chief executive officer. In the case of our named executives with employment agreements, the compensation of such individuals is determined in accordance with their respective employment agreements.

Prior to the completion of this offering, our board of directors intends to establish a compensation committee comprised of at least two independent, non-employee directors and adopt a written charter for the compensation committee setting forth the compensation committee s purpose and responsibilities. The principal responsibilities of the compensation committee will be to review and approve corporate goals and objectives relevant to the compensation of our executive officers, evaluate their performance in light of these goals and, subject to the terms of the employment agreements with our named executive officers, determine and approve our executive officers compensation based on such evaluation and establish policies, including with respect to the following:

- the determination of the elements of executive compensation and allocation among different types of executive compensation;
- the determination as to when awards are granted, including awards of equity-based compensation such as restricted stock units, restricted stock and/or options;
- stock ownership guidelines and any policies regarding hedging the economic risk of such ownership; and

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- the review of the risks and rewards associated with our compensation policies and programs.

The compensation committee will seek to provide a total compensation package designed to drive performance and reward contributions in support of our business strategies and to attract, motivate and retain high quality talent with the skills and competencies required by us. It is possible that the compensation committee will examine the compensation practices of our peer companies and may also review compensation data from the oil and natural gas industry generally to the extent the competition for executive talent is broader than a group of selected peer companies, but any decisions regarding possible benchmarking will be made following the completion of this offering. In addition, the compensation committee may review and, in certain cases, participate in, various relevant compensation surveys and consult with compensation consultants with respect to determining any changes in the compensation for our named executive officers, subject to the terms of their respective employment agreements. We expect that our Chief Executive Officer will provide periodic recommendations to the compensation committee regarding such determinations. We expect that the compensation committee will design our compensation policies and programs to encourage and reward prudent business judgment and appropriate risk taking over the long term.

Compensation Policy

Our general compensation policy is guided by several key principles:

- designing competitive total compensation programs to enhance our ability to attract and retain knowledgeable and experienced senior management level employees;
- motivating employees to deliver outstanding financial performance and meet or exceed general and specific business, operational and individual objectives;
- setting compensation and incentive levels relevant to the market in which the employee provides service; and
- providing a meaningful portion of the total compensation to our named executive officers in equity, thus assuring an alignment of interests between our senior management level employees and our stockholders.

Upon completion of this offering, our compensation committee will determine, subject to the terms of the employment agreements with our named executive officers, the mix of compensation, both among short-term and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of our named executive officers. In making compensation decisions with respect to each element of compensation, the compensation committee is expected to consider numerous factors, including:

- the individual s particular background and circumstances, including training and prior relevant work experience;
- the individual s role with us and the compensation paid to similar persons at comparable companies;
- the demand for individuals with the individual s specific expertise and experience at the time of hire;
- achievement of individual and company performance goals and other expectations relating to the position;
- comparison to other executives within our company having similar levels of expertise and experience and the uniqueness of the individual s industry skills; and

aligning the compensation of our executives with the performance of our company on both a short-term and long-term basis.

Although we expect the compensation committee to follow these policies, it is possible that the compensation committee could develop a compensation philosophy different than that discussed here.

Historic Elements of Compensation

Historically the principal elements of compensation for our named executive officers have been:

base salary;

bonus awards;

equity awards contained in their employment agreements; and

health insurance, life and disability insurance and 401(k) plan benefits available to all of our other employees.

We believe that our company does not utilize compensation policies and programs that create risks that are reasonably likely to have a material adverse impact on our company. Historically, certain management, administrative and treasury functions were provided to us by Everest, an entity controlled by Wexford, our equity sponsor. For purposes of presenting the consolidated financial statements, included elsewhere in this prospectus, allocations were made to determine the cost of general and administrative activities performed attributable to us. The allocations were made based upon underlying salary costs of employees performing Company related functions, payroll, revenue or headcount relative to other companies managed by Everest, or specifically identified invoices processed, depending on the nature of the cost. Currently, we employ all our named executive officers directly.

Components of Compensation Following the Completion of the Offering

We believe a material amount of executive compensation should be tied to our performance, and a significant portion of the total prospective compensation of each named executive officer should be tied to measurable financial and operational objectives. These objectives may include absolute performance or performance relative to a peer group. During periods when performance meets or exceeds established objectives, our named executive officers should be paid at or above targeted levels, respectively. When our performance does not meet key objectives, incentive award payments, if any, should be less than such targeted levels.

Following the completion of this offering, we anticipate that the compensation committee will seek to balance awards based on short-term annual results with awards intended to compensate our executives based on our long-term viability and success. Consequently, in addition to annual bonuses, in the future we may provide long-term incentives to our executives in the form of equity based awards to continue to align the interests of our named executive officers with those of our equity holders. These awards would be in addition to the equity awards contained in their employment agreements. In connection with this offering, our board of directors will adopt a long-term incentive plan, which we believe will further incentivize the executive officers to perform their duties in a way that will enhance our long-term success.

As discussed above, following the completion of this offering and subject to the terms of the employment agreements with our named executive officers, our compensation committee will determine the mix of compensation, both among short-term and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of our named executive officers. We believe that the mix of base salary, performance-based incentive compensation, bonus awards, existing equity awards under their employment agreements, awards under the long-term incentive plan and the other benefits that are or will be available to our named executive officers will accomplish our overall compensation objectives. We believe that these elements of compensation create competitive compensation opportunities to align and drive employee performance in support of our business strategies and to attract, motivate and retain high quality talent with the skills and competencies required by us.

Base Salary

Our named executive officers base salaries are determined in accordance with their respective employment agreements. We have not retained compensation consultants to advise us on compensation matters. Subject to applicable employment agreements, the compensation committee may increase base salaries to align such salaries with market levels for comparable positions in other companies in our industry if we identify significant market changes. Additionally, the compensation committee may adjust base salaries as warranted throughout the year for promotions or other changes in the scope or breadth of an executive s role or responsibilities. The compensation committee may also evaluate our named executive officers salaries together with other components of their compensation to ensure that the executive s total compensation is in line with our overall compensation philosophy. Upon completion of this offering, our named executive officers will, initially, continue to be compensated at their current annual rates, as specified in the Summary Compensation Table below.

Discretionary Annual Performance Bonus

In accordance with our named executive officers employment agreements, the board of directors will have the authority to award annual cash bonuses to our named executive officers that have achieved their respective performance goals determined by the board of directors for the applicable year. Pursuant to the terms of their respective employment agreements, the amount of the annual cash bonus that each of our named executive officers (with the exception of Mr. Stice) is eligible to receive is equal to 50% of such officer s annual base salary. Mr. Stice is entitled to receive an annual bonus of at least $200,000 and may receive an annual bonus of up to $400,000 upon the achievement of performance goals to be determined by the board of directors. For 2011, our named executive officers received the annual cash bonuses set forth in the table under the caption *Summary of Compensation of Our Named Executive Officers* included beginning on page 108 of this prospectus.

Long Term Equity Incentive Compensation

We will seek to promote an ownership culture among our executive officers in an effort to enhance our long-term performance. We believe the use of stock and stock-based awards offers the best approach to achieving our compensation goals. Each of our named executive officers has been awarded an option to purchase shares of our common stock in accordance with the terms of his or her employment agreement. See *Employment Agreements* beginning on page 110 of this prospectus. To date, we have not adopted stock ownership guidelines for our executives. In connection with this offering, we intend to implement an equity incentive plan. The purpose of this plan will be to continue to enable us, and our affiliates, to attract and retain the services of the types of employees, consultants and directors who will contribute to our long term success and to provide incentives that will be linked directly to increases in share value that will inure to the benefit of our stockholders. The plan will provide a means by which eligible recipients of awards may be given an opportunity to benefit from increases in value of our common stock through the granting of equity awards. The terms of our equity incentive plan are described in more detail following the Summary Compensation Table.

Other Compensation and Perquisites

Consistent with our compensation philosophy, we anticipate that our compensation committee will continue to provide benefits to our executives that are substantially the same as those currently being offered to our other employees, including health insurance, life and disability insurance and a 401(k) plan. The benefits and perquisites that may be available to our executive officers in addition to those available to our other employees include a car allowance and club dues.

Tax Implications of Executive Compensation Policy

Under Section 162(m) of the Internal Revenue Code, a public company generally may not deduct compensation in excess of $1.0 million per year per person paid to its principal executive officer, principal financial officer and the three other most highly compensated executive officers whose compensation is disclosed in its proxy statement as a result of their total compensation, subject to certain exceptions. Qualifying performance-based compensation will not be subject to the deduction limit if certain requirements are met. Although our long-term and incentive compensation plans and agreements have provisions that are intended to satisfy the performance-based compensation exception to the Section 162(m) deduction limit, regulations under Section 162(m) also provide a transition reliance period in the case of a corporation that is not publicly held and becomes publicly held in connection with an initial public offering. During the reliance period, the deduction limit of Section 162(m) does not apply to any compensation paid pursuant to a plan or agreement that existed during the period that the corporation was not publicly held, provided the prospectus accompanying the initial public offering discloses information concerning the plans or agreements in accordance with applicable securities laws. The reliance period ends on the earliest of (1) the expiration of the plan or agreement; (2) the material modification of the plan or agreement; (3) the issuance of all employer stock or compensation reserved under the plan; or (4) the first meeting of stockholders at which directors are elected that occurs after the close of the third calendar year following the calendar year in which the initial public offering occurs.

We anticipate that our compensation committee will structure our long-term and incentive compensation programs to preserve the tax deductibility of compensation paid to our executive officers. However, our compensation committee will have the authority to award performance-based compensation that is not deductible and we cannot guarantee that it will only award deductible compensation to our executive officers. In addition, notwithstanding our compensation committee s efforts, ambiguities and uncertainties regarding the application and interpretation of Section 162(m) make it impossible to provide assurance that any performance based compensation will, in fact, satisfy the requirements for deductibility under Section 162(m). Time vested restricted stock awards will not be treated as performance based compensation and, as a result, the deductibility of such awards could be limited. Also, base salaries and other non-performance based compensation as defined in Section 162(m) in excess of $1.0 million paid to these executive officers in any year would not qualify for deductibility under Section 162(m).

Summary of Compensation for Our Named Executive Officers

The following table shows the compensation of all individuals serving as our principal executive officer and principal financial officer during 2011 and of our next most highly compensated executive officer serving as of December 31, 2011, whose total compensation exceeded $100,000 for the fiscal year ended December 31, 2011.

	Year	Salary	Bonus(1)	Option Awards(2)	All Other Compensation(3)	Total
Steven E. West(4) Former Chief Executive Officer	2011	$	$	$	$	$
Travis D. Stice(5) Current Chief Executive Officer; Former President and Chief Operating Officer	2011	$ 115,879	$ 225,000	$	$ 5,874	$
Teresa L. Dick Chief Financial Officer, Senior Vice President	2011	$ 98,517	$ 112,631	$	$ 3,558	$
Jeff White Vice President Operations	2011	$ 55,846	$ 131,820	$	$ 309	$

(1) Mr. Stice received a $225,000 annual incentive bonus, Ms. Dick received a $46,820 retention bonus and a $65,811 annual incentive bonus and Mr. White received an $85,000 signing bonus and a $27,500 annual incentive bonus.

(2) Reflects the amount recognized for financial reporting purposes in 2011 under FASB ASC Topic 718 for the option award granted to each named executive officer under his or her employment agreement with us. The amount was calculated using certain assumptions set forth in Note 8 to our historical financial statements included in this prospectus.

(3) Amounts for Mr. Stice include our 401(k) plan contributions of $1,832, car allowance of $3,665 and life insurance premium payments of $377. Amounts for Ms. Dick include our 401(k) plan contributions of $2,735 and life insurance premium payments of $823. Amounts for Mr. White include life insurance premium payments of $309.

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(4) Mr. West resigned as our chief executive officer in December 2011. Mr. West did not receive any compensation from us in 2011.
(5) Mr. Stice became our President and Chief Operating Officer in April 2011. On January 1, 2012, Mr. Stice resigned as President and Chief Operating Officer and became our Chief Executive Officer. Mr. Stice s annual base salary remains at $300,000.

2011 Grants of Plan-Based Awards

The following table presents information regarding each grant of an award made to our named executive officers in 2011 under any Company plan.

Name	Grant Date	All Other Option Awards: Number of Securities Underlying Options (#)(1)	Exercise or Base Price of Option Awards ($/Sh)(2)	Grant Date Fair Value of Stock and Option Awards ($)(3)
Steve E. West				
Travis D. Stice	4/18/2011	1.00%	$ 3,600,000	
Teresa L. Dick	9/1/2011	0.25%	$ 900,000	
Jeff White	9/30/2011	0.50%	$ 2,500,000	

(1) All option awards shown represent an option to acquire a membership interest percentage in Windsor Permian. Upon the contribution to us of all the outstanding equity interests in Windsor Permian prior to the closing of this offering, an option to acquire shares of our common stock will be substituted for the option to acquire membership interests in Windsor Permian. Assuming the sale by us of shares of common stock in this offering at an estimated initial public offering price of $ per share, each of Mr. Stice s, Ms. Dick s and Mr. White s, options will be substituted for an option to acquire , and shares of our common stock, respectively.
(2) The exercise price shown represents the aggregate exercise price for the option to acquire the entire membership interest percentage in Windsor Permian.
(3) Grant date fair value of the option award granted to each named executive officer in 2011 is computed in accordance with FASB ASC Topic 718 and reflects the total amount of the award to be spread over the applicable vesting period. Each named executive officer s option award vests as described in such named executive officer s employment agreement under *Employment Agreements* below beginning on page 110.

2011 Outstanding Equity Awards at Year-End Table

The following table presents, for each of the named executive officers, information regarding outstanding equity awards held as of December 31, 2011.

	Option Awards				
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable(1)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)(2)	Option Expiration Date
Steven E. West					
Travis D. Stice		1.00%		$ 3,600,000	4/18/2016
Teresa L. Dick		0.25%		$ 900,000	9/1/2016

Jeff White	0.50%	$ 2,500,000	9/30/2016

(1) All option awards shown represent an option to acquire a membership interest percentage in Windsor Permian. Upon the contribution to us of all the outstanding equity interests in Windsor Permian prior to the closing of this offering, an option to acquire shares of our common stock will be substituted for the option to acquire membership interests in Windsor Permian. Assuming the sale by us of shares of common stock in this offering at an estimated initial public offering price of $ per share, each of Mr. Stice s, Ms. Dick s and Mr. White s options will be substituted for an option to acquire , and shares of our common stock, respectively.

(2) The exercise price shown represents the aggregate exercise price for the option to acquire the entire membership interest percentage in Windsor Permian.

Employment Agreements

The following summarizes the material terms of the employment agreements we have with our named executive officers.

Travis D. Stice. Effective April 2011, we entered into an employment agreement with Mr. Stice, our Chief Executive Officer. The employment agreement has a three-year term and provides for an annual base salary of $300,000. Mr. Stice is also entitled to receive an annual bonus of at least $200,000, which could be increased up to $400,000 depending upon his achievement of certain performance goals as determined by our board of directors. Mr. Stice is entitled to participate in such life and medical insurance plans and other similar plans that we establish from time to time for our executive employees, and is paid a $900 monthly vehicle allowance. Pursuant to the terms of his employment agreement, Mr. Stice has an option to acquire a 1.0% membership interest in our subsidiary Windsor Permian LLC for an aggregate exercise price of $3.6 million, subject to adjustment in the event of certain asset sales. Such option vests in four equal annual installments commencing on the first anniversary of the effective date of Mr. Stice s employment agreement and will be exercisable for five years from the effective date of his employment agreement or until his earlier termination. Upon the contribution of the Windsor Permian LLC membership interests to us in connection with the closing of this offering, an option to acquire shares of our common stock will be substituted for the original option to acquire membership interests in Windsor Permian LLC. The substituted option will be for such number of shares and with such exercise price as shall preserve the economic value of the original option in compliance with applicable tax requirements. The vesting schedule and exercise rights will remain the same. Mr. Stice has agreed to certain restrictive covenants in his employment agreement, including, without limitation, his agreement not to compete with us, not to interfere with any of our employees, suppliers or regulators and not to solicit our customers or employees, in each case during Mr. Stice s affiliation with us and for a period of six months thereafter. Mr. Stice s continued employment with us is at-will, meaning that either we or Mr. Stice may terminate the employment relationship at any time and for any reason, with or without notice. However, if we terminate Mr. Stice s employment without cause, we will be obligated to continue paying Mr. Stice s annual base salary until the expiration of the term of his employment agreement and pay a prorated portion of Mr. Stice s minimum annual bonus for the period prior to termination, subject to Mr. Stice s compliance with the restrictive covenants discussed above and his execution of a full general release in our favor. If Mr. Stice s employment is terminated due to death or disability, our sole obligation, subject to Mr. Stice s compliance with the restrictive covenants discussed above, will be to pay any earned but unpaid base salary and a prorated portion of Mr. Stice s minimum annual bonus for the period prior to termination. In the event Mr. Stice s employment is terminated for cause, our obligations will terminate with respect to the payment of any base salary or bonuses and the option described above effective as of the termination date. For purposes of Mr. Stice s employment agreement, cause is generally defined as Mr. Stice s (a) willful and knowing refusal or failure to perform his duties in any material respect, (b) willful misconduct or gross negligence in performing his duties, (c) material breach of his employment agreement or any other agreement with us, (d) conviction of, or a plea of guilty or nolo contendere to, a criminal act that constitutes a felony or involves fraud, dishonesty or moral turpitude, (e) indictment for a felony involving embezzlement, theft or fraud, (f) filing of a voluntary, or consent to an involuntary, bankruptcy petition or (g) failure to comply with directives of our board of directors. In addition, in the event that more than 50% of the combined voting power of our then outstanding stock is controlled by one or more parties that is not Wexford or an affiliate of Wexford, the options described above will vest immediately. The benefits Mr. Stice is entitled to receive upon certain terminations, resignations and changes of control are summarized below in *Potential Payments Upon Termination, Resignation or Change of Control* on page 115 of this prospectus.

Teresa L. Dick. Effective September 2011, we entered into an employment agreement with Ms. Dick, our Senior Vice President and Chief Financial Officer. The employment agreement has a one-year term and provides for an annual base salary of $250,000. Subject to Ms. Dick s achievement of certain performance goals as determined by our board of directors for each fiscal year, Ms. Dick is entitled to an annual bonus of 50% of her annual base salary. Ms. Dick is also entitled to participate in any life and medical insurance plans and other similar plans that we establish from time to time for our executive employees. Pursuant to the terms of her employment agreement, Ms. Dick has an option to acquire a 0.25% membership interest in our subsidiary Windsor Permian LLC for an aggregate exercise price of $900,000, subject to adjustment in the event of certain asset sales. Such option vests in four equal annual installments commencing on the first anniversary of the effective date of Ms. Dick s employment agreement and will be exercisable for five years from the effective date of such employment agreement or until her earlier termination (except for termination upon death, disability or by us without cause). Upon the contribution of the Windsor Permian LLC membership interests to us in connection with the closing of this offering, an option to acquire shares of our common stock will be substituted for the original option to acquire membership interests in Windsor Permian LLC. The substituted option will be for such number of shares and with such exercise price as shall preserve the economic value of the original option in compliance with applicable tax requirements. The vesting schedule and exercise rights will remain the same. Ms. Dick has agreed to certain restrictive covenants in her employment agreement, including, without limitation, her agreement not to compete with us, not to interfere with any of our employees, suppliers or regulators and not to solicit our customers or employees, in each case during Ms. Dick s affiliation with us and for a period of six months thereafter. Ms. Dick s continued employment with us is at-will, meaning that either we or Ms. Dick may terminate the employment relationship at any time and for any reason, with or without notice. However, if (i) we terminate Ms. Dick s employment without cause, (ii) Ms. Dick resigns for good reason, meaning such resignation follows a material uncured breach by us of the employment agreement or a material diminution in Ms. Dick s position, duties or authority, or (iii) Ms. Dick s employment is terminated due to death or disability, then we will be obligated to continue paying Ms. Dick s base annual salary until the expiration of the term of her employment agreement and, in the case of termination without cause or upon death or disability, to honor our obligations with respect to the option described above; provided, in each case, that Ms. Dick continues to comply with the restrictive covenants described above and (except in the case of clause (iii) above) executes a full general release in our favor. In the event Ms. Dick s employment is terminated for cause, our obligations will terminate with respect to the payment of any base salary or bonuses and the option described above effective as of the termination date. For purposes of Ms. Dick s employment agreement, cause is generally defined as Ms. Dick s (a) willful and knowing refusal or failure to perform her duties in any material respect, (b) willful misconduct or gross negligence in performing her duties, (c) material breach of her employment agreement or any other agreement with us, (d) conviction of, or a plea of guilty or nolo contendere to, a criminal act that constitutes a felony or involves fraud, dishonesty or moral turpitude, (e) indictment for a felony involving embezzlement, theft or fraud, (f) filing of a voluntary, or consent to an involuntary, bankruptcy petition, (g) dishonesty in connection with her responsibilities as an employee or (h) failure to comply with directives of our board of directors. In addition, (x) in the event that more than 50% of the combined voting power of our then outstanding stock is controlled by one or more parties that is not Wexford, an affiliate of Wexford or an underwriter temporarily holding securities pursuant to an offering of securities and there is a material change in Ms. Dick s position, duties or authority or (y) upon termination without cause or due to death or disability, the options described above will vest immediately. The benefits Ms. Dick is entitled to receive upon certain terminations, resignations and changes of control are summarized below in *Potential Payments Upon Termination, Resignation or Change of Control* on page 115 of this prospectus.

Jeff White. Effective September 2011, we entered into an employment agreement with Mr. White, our Vice President Operations. The employment agreement has a three-year term and provides for an annual base salary of $220,000. Subject to Mr. White s achievement of certain performance goals as determined by our board of directors for each fiscal year, Mr. White is entitled to an annual bonus of 50% of his annual base salary. Upon entering into the employment agreement, Mr. White received an $85,000 signing bonus and, if this offering is completed within one year of Mr. White s hiring, he will be entitled to receive shares of our common stock with a value equal to $170,000. If we do not complete this offering within one year of his hiring, Mr. White will receive a $170,000 cash bonus. Mr. White is also entitled to participate in any life and medical insurance plans and other similar plans that we establish from time to time for our executive employees. Pursuant to the terms of his employment agreement, Mr. White has an option to acquire a 0.5% membership interest in our subsidiary Windsor Permian LLC for an aggregate exercise price of $2.5 million, subject to adjustment in the event of certain asset sales. Such option vests in four equal annual installments commencing on the first anniversary of the effective date of Mr. White s employment agreement and will be exercisable for five years from the effective date of his employment agreement or until his earlier termination (except for termination upon death, disability or by us without cause). Upon the contribution of the Windsor Permian LLC membership interests to us in connection with the closing of this offering, an option to acquire shares of our common stock will be substituted for the original option to acquire membership interests in Windsor Permian LLC. The substituted option will be for such number of shares and with such exercise price as shall preserve the economic value of the original option in compliance with applicable tax requirements. The vesting schedule and exercise rights will remain the same. Mr. White has agreed to certain restrictive covenants in his employment agreement, including, without limitation, his agreement not to compete with us, not to interfere with any of our employees, suppliers or regulators and not to solicit our customers or employees, in each case during Mr. White s affiliation with us and for a period of six months thereafter. Mr. White s continued employment with us is at-will, meaning that either we or Mr. White may terminate the employment relationship at any time and for any reason, with or without notice. However, if (i) we terminate Mr. White s employment without cause, (ii) Mr. White resigns for good reason, meaning such resignation follows a material uncured breach by us of the employment agreement or a material diminution in Mr. White s position, duties or authority, or (iii) Mr. White s employment is terminated due to death or disability, then we will be obligated to continue paying Mr. White s base annual salary until the expiration of the term of his employment agreement and, in the case of termination without cause or upon death or disability, to honor our obligations with respect to the option described above; provided, in each case, that Mr. White continues to comply with the restrictive covenants described above and (except in the case of clause (iii) above) executes a full general release in our favor. In the event Mr. White s employment is terminated for cause, our obligations will terminate with respect to the payment of any base salary or bonuses and the option described above effective as of the termination date. For purposes of Mr. White s employment agreement, cause is generally defined as Mr. White s (a) willful and knowing refusal or failure to perform his duties in any material respect, (b) willful misconduct or gross negligence in performing his duties, (c) material breach of his employment agreement or any other agreement with us, (d) conviction of, or a plea of guilty or nolo contendere to, a criminal act that constitutes a felony or involves fraud, dishonesty or moral turpitude, (e) indictment for a felony involving embezzlement, theft or fraud, (f) filing of a voluntary, or consent to an involuntary, bankruptcy petition, (g) dishonesty in connection with his responsibilities as an employee or (h) failure to comply with directives of our board of directors. In addition, (x) in the event that more than 50% of the combined voting power of our then outstanding stock is controlled by one or more parties that is not Wexford, an affiliate of Wexford or an underwriter temporarily holding securities pursuant to an offering of securities and there is either a material change in Mr. White s position, duties or authority or Mr. White is required to move outside a 50 mile radius of Midland, Texas or (y) upon termination without cause or due to death or disability, the options described above will vest immediately. The benefits Mr. White is entitled to receive upon certain terminations, resignations and changes of control are summarized below in *Potential Payments Upon Termination, Resignation or Change of Control* on page 115 of this prospectus.

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Equity Incentive Plan

Prior to the completion of this offering, we did not have any stock option or other equity incentive plan except for the equity awards granted in the employment agreements with our named executive officers and, except for such awards, there are no stock options, restricted stock units or other equity awards outstanding for any of our named executive officers. Prior to this offering, we intend to implement our equity incentive plan.

Eligible award recipients are employees, consultants and directors of our company and its affiliates. Incentive stock options may be granted only to our employees. Awards other than incentive stock options may be granted to employees, consultants and directors. The shares that may be issued pursuant to awards consist of our authorized but unissued common stock, and the maximum aggregate amount of such common stock which may be issued upon exercise of all awards under the plan, including incentive stock options, may not exceed shares, subject to adjustment to reflect certain corporate transactions or changes in our capital structure. To the extent that an award is intended to qualify as performance-based compensation under Section 162(m) of the Internal Revenue Code, then the maximum number of shares of common stock issuable in the form of each type of award under our equity incentive plan to any one participant during a calendar year shall not exceed shares. Additionally, no participant shall receive in excess of the aggregate amount of shares pursuant to all awards issued under our equity incentive plan during any calendar year.

We anticipate granting options and restricted stock units to employees and certain non-employee directors under the plan upon completion of this offering in the amount to be determined by the compensation committee.

Share Reserve. The aggregate number of shares of common stock initially authorized for issuance under the plan is shares. However, (i) shares covered by an award that expires or otherwise terminates without having been exercised in full and (ii) shares that are forfeited to, or repurchased by, us pursuant to a forfeiture or repurchase provision under the plan may return to the plan and be available for issuance in connection with a future award.

Administration. Our board of directors (or our compensation committee or any other committee of the board of directors as may be appointed by our board of directors from time to time) administers the plan. Among other responsibilities, the plan administrator selects participants from among the eligible individuals, determines the number of shares that will be subject to each award and determines the terms and conditions of each award, including methods of payment, vesting schedules and limitations and restrictions on awards. The plan administrator may amend, suspend, or terminate the plan at any time. Amendments will not be effective without stockholder approval if stockholder approval is required by applicable law or stock exchange requirements. Unless terminated earlier, our equity incentive plan will terminate in , 2022.

Stock Options. Incentive and nonstatutory stock options are granted pursuant to incentive and nonstatutory stock option agreements. Employees, directors and consultants may be granted nonstatutory stock options, but only employees may be granted incentive stock options. The plan administrator determines the exercise price of a stock option, provided that the exercise price of a stock option generally cannot be less than 100% (and in the case of an incentive stock option granted to a more than 10% stockholder, 110%) of the fair market value of our common stock on the date of grant, except when assuming or substituting options in limited situations such as an acquisition. Generally, options granted under the plan vest ratably over a five-year period and have a term of ten years (five years in the case of an incentive stock option granted to a more than 10% stockholder), unless specified otherwise by the plan administrator in the option agreement.

Acceptable consideration for the purchase of common stock issued upon the exercise of a stock option will be determined by the plan administrator and may include (i) cash or check, (ii) a broker-assisted cashless exercise, (iii) the tender of common stock previously owned by the optionee, (iv) stock withholding and (v) other legal consideration approved by the plan administrator, such as exercise with a full recourse promissory note (not applicable for directors and executive officers).

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Unless the plan administrator provides otherwise (solely with respect to intervivos transfers to certain family members and estate planning vehicles), nonstatutory options generally are not transferable except by will or the laws of descent and distribution. An optionee may designate a beneficiary, however, who may exercise the option following the optionee s death. Incentive stock options are not transferable except by will or the laws of descent and distribution.

Restricted Awards. Restricted awards are awards of either actual shares of common stock (e.g., restricted stock awards), or of hypothetical share units (e.g., restricted stock units) having a value equal to the fair market value of an identical number of shares of common stock, that will be settled in the form of shares of common stock upon vesting or other specified payment date, and which may provide that such restricted awards may not be sold, transferred, or otherwise disposed of for such period as the plan administrator determines. The purchase price and vesting schedule, if applicable, of restricted awards are determined by the plan administrator. A restricted stock unit is similar to a restricted stock award except that participants holding restricted stock units do not have any stockholder rights until the stock unit is settled with shares. Stock units represent an unfunded and unsecured obligation for us and a holder of a stock unit has no rights other than those of a general creditor.

Performance Awards. Performance awards entitle the recipient to vest in or acquire shares of common stock, or hypothetical share units having a value equal to the fair market value of an identical number of shares of common stock that will be settled in the form of shares of common stock upon the attainment of specified performance goals. Performance awards may be granted independent of or in connection with the granting of any other award under the plan. Performance goals will be established by the plan administrator based on one or more business criteria that apply to the plan participant, a business unit, or our company and our affiliates. Performance goals will be objective and will be intended to meet the requirements of Section 162(m) of the Code. Performance goals must be determined prior to the time 25% of the service period has elapsed but not later than 90 days after the beginning of the service period. No payout will be made on a performance award granted to a named executive officer unless all applicable performance goals and service requirements are achieved. Performance awards may not be sold, assigned, transferred, pledged or otherwise encumbered and terminate upon the termination of the participant s service to us or our affiliates.

Stock Appreciation Rights. Stock appreciation rights may be granted independent of or in tandem with the granting of any option under the plan. Stock appreciation rights are granted pursuant to stock appreciation rights agreements. The exercise price of a stock appreciation right granted independent of an option is determined by the plan administrator, but as a general rule will be no less than 100% of the fair market value of our common stock on the date of grant. The exercise price of a stock appreciation right granted in tandem with an option is the same as the exercise price of the related option. Upon the exercise of a stock appreciation right, we will pay the participant an amount equal to the product of (i) the excess of the per share fair market value of our common stock on the date of exercise over the strike price, multiplied by (ii) the number of shares of common stock with respect to which the stock appreciation right is exercised. Payment will be made in cash, delivery of stock, or a combination of cash and stock as deemed appropriate by the plan administrator.

Adjustments in capitalization. In the event that there is a specified type of change in our common stock without the receipt of consideration by us, such as pursuant to a merger, consolidation, reorganization, recapitalization, reincorporation, stock dividend, dividend in property other than cash, stock split, liquidating dividend, combination of shares, exchange of shares, change in corporate structure or other transaction, appropriate adjustments will be made to the various limits under, and the share terms of, the plan including (i) the number and class of shares reserved under the plan, (ii) the maximum number of stock options and stock appreciation rights that can be granted to any one person in a calendar year and (iii) the number and class of shares and exercise price, strike price, or purchase price, if applicable, of all outstanding stock awards.

Corporate Transactions. In the event of a change in control transaction (other than a transaction resulting in Wexford or an entity controlled by, or under common control with Wexford maintaining direct or indirect control over the Company), or a corporate transaction such as a dissolution or liquidation of our company, or any

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corporate separation or division, including, but not limited to, a split-up, a split-off or a spin-off, or a sale in one or a series of related transactions, of all or substantially all of the assets of our company or a merger, consolidation, or reverse merger in which we are not the surviving entity, then all outstanding stock awards under the plan may be assumed, continued or substituted for by any surviving or acquiring entity (or its parent company), or may be cancelled either with or without consideration for the vested portion of the awards, all as determined by the plan administrator. In the event an award would be cancelled without consideration paid to the extent vested, the award recipient may exercise the award in full or in part for a period of ten days.

401(k) Plan

We participate in a 401(k) Plan. Employees may elect to defer a portion of their compensation up to the statutorily prescribed limit. Each pay period we make a matching contribution to each employee s deferral, not to exceed six percent. An employee s interests in his or her deferrals are 100% vested when contributed. An employee s interests in the matching contribution are vested at the rate of 20% for each completed year of eligibility. The 401(k) Plan is intended to qualify under Section 401(a) of the Internal Revenue Code. As such, contributions to the 401(k) Plan and earnings on those contributions are not taxable to the employee until distributed from the 401(k) Plan, and all contributions are deductible by us when made.

Potential Payments Upon Termination, Resignation or Change of Control

The following table shows the estimated benefits payable to our named executive officers in various hypothetical scenarios as of December 31, 2011:

	Termination Without Cause or Upon Death or Disability[(1)(2)]				Resignation for Good Reason[(3)]				Change of Control			
Name	Base Salary	Benefits	Options	Total	Base Salary	Benefits	Options	Total	Base Salary	Benefits	Options	Total
Steven West												
Travis D. Stice[(4)]	$ 688,767[(6)]			$ 688,767[(6)]								
Teresa L. Dick[(5)]	$ 186,986[(7)]			$ 186,986[(7)]								
Jeff White[(5)]	$ 659,507[(8)]			$ 659,507[(8)]								

(1) In the event a named executive officer (except for Mr. West) is terminated upon death or disability, the receipt of the payments and benefits described in this table is subject to such executive s continued compliance with the non-competition, confidentiality, non-interference, proprietary information, return of property, non-solicitation and non-disparagement provisions of such executive s employment agreement.

(2) In the event a named executive officer is terminated without cause, the receipt of the payments and benefits described in this table are subject to (a) such executive s continued compliance with the non-competition, confidentiality, non-interference, proprietary information, return of property, non-solicitation and non-disparagement provisions of such executive s employment agreement and (b) such executive executing (and not revoking) a full general release of all claims, known or unknown against us, Wexford and various other parties affiliated with Wexford.

(3) Under the terms of the employment agreements with our named executive officers (except for Mr. Stice), the applicable officer is entitled to certain benefits in the event such officer resigns for good cause, which means such resignation follows any (a) material breach by us of the terms of the applicable employment agreement or (b) material diminution in the officer s position, duties or authority which in either case is not cured within thirty (30) business days following our receipt of notice thereof, subject to (i) such executive s continued compliance with the non-competition, confidentiality, non-interference, proprietary information, return of property, non-solicitation and non-disparagement provisions of such executive s employment agreement and (ii) such executive executing (and not revoking) a full general release of all claims, known or unknown against us, Wexford and various other parties affiliated with Wexford.

(4) Under the terms of Mr. Stice s employment agreement, Mr. Stice s stock options granted pursuant to such agreement shall vest immediately in the event that more than 50% of the combined voting power of our then outstanding stock is controlled by one or more parties that is not us, Wexford or an affiliate of Wexford.

(5) Under the terms of our employment agreement with each of Ms. Dick and Mr. White the stock options granted under such agreement will vest immediately (a) in the event that more than 50% of the combined voting power of our then outstanding stock is controlled by one or more parties that is not us, Wexford, an affiliate of Wexford or an underwriter temporarily holding securities pursuant to an offering of securities and either there is a material change in the applicable named executive officer s position, duties or authority or such officer is required to relocate to a location outside of a 50 mile radius of Midland, Texas or (b) upon termination without cause or upon death or disability.

(6) Represents the amount payable under Mr. Stice s employment agreement and is equal to Mr. Stice s base salary for the remainder of the term of his employment agreement, which expires on April 18, 2014.

(7) Represents the amount payable under Ms. Dick s employment agreement and is equal to Mr. Dick s base salary for the remainder of the term of her employment agreement, which expires on September 30, 2012.

(8) Represents the amount payable under Mr. White s employment agreement and is equal to Mr. White s base salary for the remainder of the term of his employment agreement, which expires on September 30, 2014.

Limitations on Liability and Indemnification of Officers and Directors

Certificate of Incorporation and Bylaws

Our certificate of incorporation provides that no director shall be personally liable to us or any of our stockholders for monetary damages resulting from breaches of their fiduciary duty as directors, except to the extent such limitation on or exemption from liability is not permitted under the Delaware General Corporation Law, or DGCL. The effect of this provision of our certificate of incorporation is to eliminate our rights and those of our stockholders (through stockholders derivative suits on our behalf) to recover monetary damages against a director for breach of the fiduciary duty of care as a director, including breaches resulting from negligent or grossly negligent behavior, except, as restricted by the DGCL:

- for any breach of the director s duty of loyalty to the company or its stockholders;
- for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law;
- in respect of certain unlawful dividend payments or stock redemptions or repurchases; and
- for any transaction from which the director derives an improper personal benefit.

This provision does not limit or eliminate our rights or the rights of any stockholder to seek non-monetary relief, such as an injunction or rescission, in the event of a breach of a director s duty of care.

Our certificate of incorporation also provides that we will, to the fullest extent permitted by Delaware law, indemnify our directors and officers against losses that they may incur in investigations and legal proceedings resulting from their service.

Our bylaws include provisions relating to advancement of expenses and indemnification rights consistent with those provided in our certificate of incorporation. In addition, our bylaws provide:

- for a right of indemnitee to bring a suit in the event a claim for indemnification or advancement of expenses is not paid in full by us within a specified period of time; and permit us to purchase and maintain insurance, at our expense, to protect us and any of our directors, officers and employees against any loss, whether or not we would have the power to indemnify that person against that loss under Delaware law.

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Indemnification Agreements

We will enter into indemnification agreements with each of our current directors and executive officers effective upon the closing of this offering. These agreements require us to indemnify these individuals to the fullest extent permitted under Delaware law against liabilities that may arise by reason of their service to us, and to advance expenses incurred as a result of any proceeding against them as to which they could be indemnified. We also intend to enter into indemnification agreements with our future directors and executive officers.

Liability Insurance

We intend to provide liability insurance for our directors and officers, including coverage for public securities matters. There is no pending litigation or proceeding involving any of our directors, officers or employees for which indemnification from us is sought. We are not aware of any threatened litigation that may result in claims for indemnification from us.

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RELATED PARTY TRANSACTIONS

Review and Approval of Related Party Transactions

We do not currently have a written policy regarding the review and approval of related party transactions, but intend to implement such a policy in connection with, and prior to the completion of, this offering. In connection with this offering, we will establish an audit committee consisting solely of independent directors whose functions will be set forth in the audit committee charter. We anticipate that one of the audit committee s functions will be to review and approve all relationships and transactions in which we and our directors, director nominees and executive officers and their immediate family members, as well as holders of more than 5% of any class of our voting securities and their immediate family members, have a direct or indirect material interest. We anticipate that such policy will be a written policy included as part the audit committee charter that will be implemented by the audit committee and in the Code of Business Conduct and Ethics that our board of directors will adopt prior to the completion of this offering.

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

Our management will continue to review and approve related party transactions, subject to the above-referenced conflicts of interest policy, until the adoption of the policy regarding the review and approval of such transactions by the audit committee, which we intend to adopt in connection with, and prior to the completion of, this offering.

Gulfport Contribution and Investor Rights Agreement

On May 7, 2012, we entered into a contribution agreement with Gulfport in which Gulfport agreed to contribute to us, prior to the closing of this offering, all of its oil and natural gas interests in the Permian Basin in exchange for (i) shares of our common stock representing 35% of our common stock outstanding immediately prior to the closing of this offering and (ii) approximately $63.6 million in the form of a non-interest bearing promissory note that will be repaid in full upon the closing of this offering with a portion of the net proceeds from this offering. The aggregate consideration payable to Gulfport is subject to a post-closing cash adjustment based on changes in our working capital, long-term debt and certain other items identified in the contribution agreement as of the date of the contribution. Gulfport s obligation to make this contribution is contingent upon, among other things, the contribution to us of all the outstanding equity interests in Windsor Permian and Gulfport s satisfaction with the terms of this offering. Under the contribution agreement, Gulfport is generally responsible for all liabilities and obligations with respect to the contributed properties arising prior to the contribution and we are responsible for such liabilities and obligations arising after the contribution. At the closing of the Gulfport contribution, we will enter into an investor rights agreement with Gulfport in which Gulfport will be granted certain (i) demand and piggyback registration rights, (ii) director nomination rights and (iii) information rights. For additional information regarding the terms of the contribution agreement and the investor rights agreement, see *Prospectus Summary The Contributions*, *Management Our Board of Directors and Committees* and *Shares Eligible for Future Sale Registration Rights* beginning on pages 6, 103 and 128, respectively, of this prospectus. Mike Liddell, who served as the Operating Member and Chairman of Windsor Permian prior to the completion of this offering, is also the Chairman of the Board and a director of Gulfport and has an interest in DB Holdings. Charles E. Davidson, the Chairman and Chief Investment Officer of Wexford, beneficially owned approximately 9.5% of Gulfport s outstanding common stock as of March 13, 2012.

Administrative Services

We are a party to a shared services agreement, dated March 1, 2008, with Everest Operations Management LLC (formerly, Windsor Energy Resources LLC), or Everest, an entity controlled by Wexford, our equity sponsor. Under this agreement, Everest provides us with technical, administrative and payroll services and office space in Oklahoma City, Oklahoma and we reimburse Everest in an amount determined by Everest s management based on estimates of the amount of office space provided and the amount of its employees time spent performing services for us. Historically, certain management, administrative, employee and treasury functions and office space were provided to us by Everest. For purposes of presenting the consolidated financial statements, included elsewhere in this prospectus, allocations were made to determine the cost of general and administrative activities performed attributable to us. The allocations were made based upon underlying salary costs of employees performing Company related functions, payroll, revenue or headcount relative to other companies managed by Everest, or specifically identified invoices processed, depending on the nature of the cost.

The initial term of the shared services agreement with Everest was two years. Since the expiration of such two-year period on March 1, 2010, the agreement, by its terms, has continued on a month-to-month basis and

will continue to do so until terminated by either party upon thirty days prior written notice. For the years ended December 31, 2011, 2010 and 2009, we incurred total costs to Everest of approximately $10.0 million, $8.0 million and $5.5 million, respectively, and at December 31, 2011, 2010 and 2009, we owed $0.8 million, $0.4 million and $0.9 million, respectively, under this shared services agreement. We expect to discontinue all services under this shared services agreement prior to the closing of this offering.

Wexford Contribution

The historical financial and operating information included in this prospectus pertains to the assets, liabilities, revenues and expenses of Windsor Permian. Prior to the completion of this offering, Wexford will cause DB Holdings to contribute all of the outstanding equity interests in Windsor Permian to us in exchange for shares of our common stock and Windsor Permian will become our wholly-owned subsidiary. In addition, Wexford has agreed to cause all the outstanding equity interests in Windsor UT to be contributed to Windsor Permian prior to the time Windsor Permian is contributed to us. For additional information regarding this contribution by Wexford, see *Prospectus Summary Our History* on page 8 of this prospectus.

Drilling Services

Bison Drilling and Field Services LLC, or Bison, has performed drilling and field services for us under master drilling agreements. Under our most recent master drilling agreement with Bison, effective as of January 1, 2012, Bison committed to accept orders from us for the use of at least two of its rigs, and is currently providing drilling services to us using four of its rigs. This master drilling agreement is terminable by either party on 30 day s 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. Bison was a wholly-owned subsidiary of Windsor Permian until March 31, 2011, when various entities controlled by Wexford started contributing capital to Bison. These contributions aggregated $11.5 million and ultimately diluted Windsor Permian s ownership interest to 52.2%. In September 2011, Windsor Permian sold a 25% interest in Bison to Gulfport for $6.0 million, subject to adjustment. At the time of the transaction, an affiliate of Wexford beneficially owned approximately 13.3% of Gulfport s common stock, but that ownership is now less than 10%. In April 2012, Gulfport increased its ownership interest in Bison to 40%. As a result of these transactions, Windsor Permian s ownership interest in Bison was reduced to 22%, with the remaining equity interests in Bison held by Gulfport and various entities controlled by Wexford. Prior to its contribution to us, Windsor Permian will distribute its remaining interest in Bison to its member. As a result, we will not own any interest in Bison when all the outstanding equity interests in Windsor Permian are contributed to us prior to the completion of this offering. For the period April 1, 2011 through December 31, 2011, we were billed $16.3 million by Bison for drilling services. At December 31, 2011, we had a payable due to Bison of $0.2 million.

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Completion and Well Servicing Services

We contracted with Great White Energy Services, or Great White, an entity formerly controlled by Wexford, for certain well completion services. For the year ended December 31, 2010 and 2009, we were billed $7.7 million and $3.3 million by Great White, and we owed $3.1 million for such services at December 31, 2010 and no amounts at December 31, 2009. Effective August 24, 2011, Great White was sold to an unrelated third party and, therefore, Great White is no longer a related party. While still a related party, during the year ended December 31, 2011 Great White billed us $12.5 million for such services.

Marketing Services

On March 1, 2009, we entered into an agreement with Windsor Midstream LLC, or Midstream, an entity controlled by Wexford, pursuant to which Midstream purchased a significant portion of our oil volumes. For the years ended December 31, 2011, 2010 and 2009, our revenues from Midstream were $38.2 million, $21.4 million and $8.8 million, respectively, and at December 31, 2011, 2010 and 2009 we had an accounts receivable balance of $4.1 million, $2.7 million and $1.5 million, respectively. Effective December 1, 2011, we ceased all sales of our oil production to Midstream under this agreement.

Midland Lease

We occupy our corporate headquarters in Midland, Texas under a five-year lease, effective May 15, 2011, with Fasken Midland, LLC, or Fasken, an entity controlled by an affiliate of Wexford. Through December 31, 2011, we paid $40,080 to Fasken under this lease. Our current monthly rent under the lease is $7,593, which amount will increase approximately 4% annually on June 1 of each year during the remainder of the lease term.

Area of Mutual Interest and Related Agreements

Effective as of November 1, 2007, we and Gulfport entered into an area of mutual interest agreement to jointly acquire oil and gas leases in the Permian Basin. The agreement provides that each party must offer the other party the right to participate in 50% of each such acquisition. The parties also agreed, subject to certain exceptions, to share third-party costs and expenses in proportion to their respective participating interests and pay certain other fees as provided in the agreement. The agreement continues in force on a month-to-month basis until terminated by either party upon 30 days prior written notice.

In connection with the area of mutual interest agreement, we, Gulfport and Windsor Energy Group, L.L.C., or Energy Group, an entity controlled by Wexford, as the operator, entered into a joint development agreement, effective as of November 1, 2007, pursuant to which we and Gulfport agreed to develop certain jointly-held oil and gas leases in the Permian Basin and Energy Group agreed to act as the operator under the terms of a joint operating agreement, effective as of November 1, 2007. In the event either party has a majority interest in a prospect (as defined in the development agreement), the majority party may designate the operator of its choice. The parties agreed to designate Energy Group as the operator with respect to the contract area as provided in the joint operating agreement. As operator of these properties, Energy Group was responsible for the daily operations, monthly operation billings and monthly revenue disbursements for the properties in which we held an interest. Effective February 26, 2010, the agreement with Energy Group was terminated and we became the operator of these properties. As of December 31, 2011 we did not owe Energy Group any amounts. For the years ended December 31, 2010 and 2009, Energy Group billed us approximately $3.8 million and $20.4 million, respectively, and at December 31, 2010 and 2009, we owed $0.07 million and $2.8 million, respectively, for these services.

Upon becoming operator effective February 26, 2010, we began providing joint interest billing services to certain of our affiliates. For the years ended December 31, 2011 and 2010, we billed Gulfport $56.7 million and $32.4 million, respectively, and we billed an entity controlled by Wexford $5.3 million and $8.8 million, respectively, for such services. At December 31, 2011 and 2010, Gulfport owed us $4.5 million and $4.6 million, respectively, and the Wexford controlled entity owed us $0.4 million and zero, respectively.

Our area of mutual interest agreement and joint development agreement, each with Gulfport, will be terminated upon the Gulfport contribution.

Investment in Muskie Holdings LLC

During 2011, Windsor Permian purchased certain assets, real estate and rights in a lease covering land in Wisconsin that is prospective for mining oil and natural gas fracture grade sand for $4.1 million from an unrelated third party. On October 7, 2011, Windsor Permian contributed these assets, real estate and lease rights to a newly-formed entity, Muskie Holdings LLC, or Muskie, in exchange for a 48.6% equity interest. The remaining equity interests in Muskie are held 25% by Gulfport and 26.4% by entities controlled by Wexford. Through additional contributions from the Wexford-controlled entities to Muskie, Windsor Permian s equity interest decreased to approximately 33%. Prior to its contribution to us, Windsor Permian will distribute its remaining interest in Muskie to its member. As a result, we will not own any interest in Muskie when all the outstanding equity interests in Windsor Permian are contributed to us prior to the completion of this offering.

MidMar

We are party to a gas purchase agreement, dated May 1, 2009, as amended, with MidMar Gas LLC, or MidMar, an entity that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, MidMar is obligated to purchase from us, and we are obligated to sell to MidMar, all of the gas conforming to certain quality specifications produced from certain of our Permian Basin acreage. Following the expiration of the initial ten-year term, the agreement will continue on a year-to-year basis until terminated by either party on 30 days written notice. Under the gas purchase agreement, MidMar is obligated to pay us a percentage of the net revenue received by MidMar for all components of our dedicated gas. Travis D. Stice, our Chief Executive Officer, has served as a manager on MidMar s board of managers since April 2011 and as Vice President and Secretary of MidMar since April 2012. An entity controlled by Wexford in which Gulfport and certain entities controlled by Wexford are members owns approximately a 28% equity interest in MidMar. The remaining equity interests in MidMar are owned by nonaffiliated third parties. For the years ended December 31, 2011 and 2010, MidMar paid us $12.2 million and $0.9 million, respectively, and at December 31, 2011 and 2010, MidMar owed us $0.2 million and $0.1 million, respectively, for our portion of the net proceeds from the sale of such gas products and residue gas by MidMar. We were not paid, nor were we owed, any amounts for 2009 by MidMar.

Advisory Services Agreement

Prior to the closing of this offering we will enter into an advisory services agreement with Wexford under which Wexford will provide us with general financial and strategic advisory services related to our business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. This agreement has a term of two years commencing on the completion of this offering. The parties may extend the then current term for additional one-year periods by entering into a written agreement reflecting the terms of such extension at least ten days prior to the expiration of the then current term. The agreement may be terminated at any time by either party upon 30 days prior written notice. In the event we terminate the agreement, we are obligated to pay all amounts due through the remaining term of the agreement. In addition, in this agreement we have agreed to pay Wexford to-be-negotiated market-based fees approved by our independent directors for such services as may be provided by Wexford at our request in connection with future acquisitions and divestitures, financings or other transactions in which we may be involved. The services provided by Wexford under the advisory services agreement will not extend to our day-to-day business or operations.

Registration Rights

Prior to the closing of this offering, we will enter a registration rights agreements with DB Holdings and Gulfport under which we will grant DB Holdings and Gulfport certain demand and piggyback registration rights. For more information regarding this agreement, see *Shares Eligible for Future Sale Registration Rights* on page 128 of this prospectus.

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PRINCIPAL AND SELLING STOCKHOLDERS

The following table sets forth certain information with respect to the beneficial ownership of our common stock by:

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

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

	Shares Beneficially Owned Prior to Offering			Shares Beneficially Owned After Offering(1)		Shares to be Sold if Option to Purchase Additional Shares Is Exercised in Full	Shares Beneficially Owned After Offering if Option to Purchase Additional Shares Is Exercised in Full	
Name of Beneficial Owner	Number	Percentage	Number of Shares Offered	Number	Percentage		Number	Percentage
Selling Stockholders and other 5% Stockholders:								
DB Energy Holdings LLC(2)								
Gulfport Energy Corporation								
Executive Officers and Directors:								
Travis D. Stice								
Teresa L. Dick								
Russell Pantermuehl								
Paul Molnar								
Michael Hollis								
William Franklin								
Jeff White								
Randall J. Holder								
Steven E. West								
All executive officers and directors as a group (9 persons)								

(1) Percentage of beneficial ownership is based upon shares of common stock outstanding immediately prior to the offering after giving effect to the Contributions, and shares of common stock outstanding after the offering. For purposes of this table, a person or group of persons is deemed to have beneficial ownership of any shares which such person has the right to acquire within 60 days. For purposes of computing the percentage of outstanding shares held by each person or group of persons named above, any security which such person or group of persons has the right to acquire within 60 days is deemed to be outstanding for the purpose of computing the percentage

ownership for such person or persons, but is not deemed to be outstanding for the purpose of computing the percentage ownership of any other person. As a result, the denominator used in calculating the beneficial ownership among our stockholders may differ.

(2) Wexford is the manager of DB Holdings, which is one of the selling stockholders in this offering. The number of shares to be sold in the offering by DB Holdings includes up to shares that will be sold if the underwriters exercise their option to purchase additional shares in full. As manager of DB Holdings, Wexford has the exclusive authority to,

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among other things, purchase, hold and dispose of its assets, including the shares of our common stock that will be owned by DB Holdings. Wexford may, by reason of its status as manager of DB Holdings, be deemed to beneficially own the interest in the shares of our common stock owned by DB Holdings. Each of Charles E. Davidson and Joseph M. Jacobs may, by reason of his status as a controlling person of Wexford, be deemed to beneficially own the interests in the shares of our common stock owned by DB Holdings. Each of Charles E. Davidson, Joseph M. Jacobs and Wexford share the power to vote and to dispose of the interests in the shares of our common stock owned by DB Holdings. Each of Messrs. Davidson and Jacobs disclaims beneficial ownership of the shares of our common stock owned by DB Holdings and Wexford. Wexford s address is Wexford Plaza, 411 West Putnam Avenue, Greenwich, Connecticut 06830.

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DESCRIPTION OF CAPITAL STOCK

We will amend and restate our certificate of incorporation and bylaws in connection with this offering. The following description of our common stock, certificate of incorporation and our bylaws are summaries thereof and are qualified by reference to our certificate of incorporation and our bylaws as so amended and restated, copies of which will be filed with the SEC as exhibits to the registration statement of which this prospectus is a part.

Our authorized capital stock consists of shares of common stock, par value $0.01 per share, and shares of preferred stock, par value $0.01 per share. We have applied to have our shares of common stock listed on The NASDAQ Global Market under the symbol FANG.

Common Stock

Holders of shares of common stock are entitled to one vote per share on all matters submitted to a vote of stockholders. Shares of common stock do not have cumulative voting rights, which means that the holders of more than 50% of the shares voting for the election of the board of directors can elect all the directors to be elected at that time, and, in such event, the holders of the remaining shares will be unable to elect any directors to be elected at that time. Our certificate of incorporation denies stockholders any preemptive rights to acquire or subscribe for any stock, obligation, warrant or other securities of ours. Holders of shares of our common stock have no redemption or conversion rights nor are they entitled to the benefits of any sinking fund provisions.

In the event of our liquidation, dissolution or winding up, holders of shares of common stock shall be entitled to receive, pro rata, all the remaining assets of our company available for distribution to our stockholders after payment of our debts and after there shall have been paid to or set aside for the holders of capital stock ranking senior to common stock in respect of rights upon liquidation, dissolution or winding up the full preferential amounts to which they are respectively entitled.

Holders of record of shares of common stock are entitled to receive dividends when and if declared by the board of directors out of any assets legally available for such dividends, subject to both the rights of all outstanding shares of capital stock ranking senior to the common stock in respect of dividends and to any dividend restrictions contained in debt agreements. All outstanding shares of common stock and any shares sold and issued in this offering will be fully paid and nonassessable by us.

Preferred Stock

Our board of directors is authorized to issue up to shares of preferred stock in one or more series. The board of directors may fix for each series:

- the distinctive serial designation and number of shares of the series;
- the voting powers and the right, if any, to elect a director or directors;
- the terms of office of any directors the holders of preferred shares are entitled to elect;
- the dividend rights, if any;
- the terms of redemption, and the amount of and provisions regarding any sinking fund for the purchase or redemption thereof;
- the liquidation preferences and the amounts payable on dissolution or liquidation;

the terms and conditions under which shares of the series may or shall be converted into any other series or class of stock or debt of the corporation; and

any other terms or provisions which the board of directors is legally authorized to fix or alter.

We do not need stockholder approval to issue or fix the terms of the preferred stock. The actual effect of the authorization of the preferred stock upon your rights as holders of common stock is unknown until our board of directors determines the specific rights of owners of any series of preferred stock. Depending upon the rights granted to any series of preferred stock, your voting power, liquidation preference or other rights could be adversely affected. Preferred stock may be issued in acquisitions or for other corporate purposes. Issuance in connection with a stockholder rights plan or other takeover defense could have the effect of making it more difficult for a third party to acquire, or of discouraging a third party from acquiring, control of our company. We have no present plans to issue any shares of preferred stock.

Related Party Transactions and Corporate Opportunities

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 so long as it has been approved by our board of directors;

- 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.

Anti-takeover Effects of Provisions of Our Certificate of Incorporation and Our Bylaws

Some provisions of our certificate of incorporation and our bylaws contain provisions that could make it more difficult to acquire us by means of a merger, tender offer, proxy contest or otherwise, or to remove our incumbent officers and directors. These provisions, summarized below, are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with our board of directors. We believe that the benefits of increased protection of our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging such proposals because negotiation of such proposals could result in an improvement of their terms.

Undesignated preferred stock. The ability to authorize and issue undesignated preferred stock may enable our board of directors to render more difficult or discourage an attempt to change control of us by means of a merger, tender offer, proxy contest or otherwise. For example, if in the due exercise of its fiduciary obligations, the board of directors were to determine that a takeover proposal is not in our best interest, the board of directors could cause shares of preferred stock to be issued without stockholder approval in one or more private offerings or other transactions that might dilute the voting or other rights of the proposed acquirer or insurgent stockholder or stockholder group.

Stockholder meetings. Our certificate of incorporation and bylaws provide that a special meeting of stockholders may be called only by the Chairman of the Board, the Chief Executive Officer or by a resolution adopted by a majority of our board of directors.

Requirements for advance notification of stockholder nominations and proposals. Our bylaws establish advance notice procedures with respect to stockholder proposals and the nomination of candidates for election as directors, other than nominations made by or at the direction of the board of directors.

Stockholder action by written consent. Our bylaws provide that, except as may otherwise be provided with respect to the rights of the holders of preferred stock, no action that is required or permitted to be taken by our stockholders at any annual or special meeting may be effected by written consent of stockholders in lieu of a meeting of stockholders, unless the action to be effected by written consent of stockholders and the taking of such action by such written consent have expressly been approved in advance by our board. This provision, which may not be amended except by the affirmative vote of at least 66 2/3% of the voting power of all then outstanding shares of capital stock entitled to vote generally in the election of directors, voting together as a single class, makes it difficult for stockholders to initiate or effect an action by written consent that is opposed by our board.

Amendment of the bylaws. Under Delaware law, the power to adopt, amend or repeal bylaws is conferred upon the stockholders. A corporation may, however, in its certificate of incorporation also confer upon the board of directors the power to adopt, amend or repeal its bylaws. Our certificate of incorporation and bylaws grant our board the power to adopt, amend and repeal our bylaws at any regular or special meeting of the board on the affirmative vote of a majority of the directors then in office. Our stockholders may adopt, amend or repeal our bylaws but only at any regular or special meeting of stockholders by an affirmative vote of holders of at least 66 2/3% of the voting power of all then outstanding shares of capital stock entitled to vote generally in the election of directors, voting together as a single class.

Removal of Director. Our certificate of incorporation and bylaws provide that members of our board of directors may only be removed by the affirmative vote of holders of at least 66 2/3% of the voting power of all then outstanding shares of capital stock entitled to vote generally in the election of directors, voting together as a single class.

Amendment of the Certificate of Incorporation. Our certificate of incorporation provides that, in addition to any other vote that may be required by law or any preferred stock designation, the affirmative vote of the holders of at least 66 2/3% of the voting power of all then outstanding shares of capital stock entitled to vote generally in the election of directors, voting together as a single class, is required to amend, alter or repeal, or adopt any provision as part of our certificate of incorporation inconsistent with the provisions of our certificate of incorporation dealing with distributions on our common stock, related party transactions, our board of directors, our bylaws, meetings of our stockholders or amendment of our certificate of incorporation.

The provisions of our certificate of incorporation and bylaws could have the effect of discouraging others from attempting hostile takeovers and, as a consequence, they may also inhibit temporary fluctuations in the market price of our common stock that often result from actual or rumored hostile takeover attempts. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish transactions which stockholders may otherwise deem to be in their best interests.

Transfer Agent and Registrar

will be the transfer agent and registrar for our common stock.

SHARES ELIGIBLE FOR FUTURE SALE

Prior to this offering, there has been no public market for our common stock. Future sales of substantial amounts of our common stock in the public market, or the perception that such sales may occur, could adversely affect the prevailing market price of our common stock. We cannot predict the effect, if any, that future sales of shares, or the availability of shares for future sales, will have on the market price of our common stock prevailing from time to time.

Sale of Restricted Shares

Upon completion of this offering, we will have shares of common stock outstanding. Of these shares of common stock, the shares of common stock being sold in this offering, plus any shares sold upon exercise of the underwriters option to purchase additional shares, will be freely tradable without restriction under the Securities Act, except for any such shares held or acquired by an affiliate of ours, as that term is defined in Rule 144 promulgated under the Securities Act, which shares will be subject to the volume limitations and other restrictions of Rule 144 described below. The remaining shares of common stock held by our existing stockholder upon completion of this offering, or shares if the underwriters exercise their option to purchase additional shares in full, will be restricted securities, as that phrase is defined in Rule 144, and may be resold only after registration under the Securities Act or pursuant to an exemption from such registration, including, among others, the exemptions provided by Rule 144 and 701 under the Securities Act, which rules are summarized below. These remaining shares of common stock held by our existing stockholder upon completion of this offering will be available for sale in the public market after the expiration of the lock-up agreements described in *Underwriting* beginning on page 133 of this prospectus, taking into account the provisions of Rules 144 and 701 under the Securities Act.

Rule 144

In general, under Rule 144 as currently in effect, persons who became the beneficial owner of shares of our common stock prior to the completion of this offering may sell their shares upon the earlier of (1) the expiration of a six-month holding period, if we have been subject to the reporting requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act), for at least 90 days prior to the date of the sale and have filed all reports required thereunder, or (2) the expiration of a one-year holding period.

At the expiration of the six-month holding period, assuming we have been subject to the Exchange Act reporting requirements for at least 90 days and have filed all reports required thereunder, a person who was not one of our affiliates at any time during the three months preceding a sale would be entitled to sell an unlimited number of shares of our common stock, and a person who was one of our affiliates at any time during the three months preceding a sale would be entitled to sell, within any three-month period, a number of shares of common stock that does not exceed the greater of either of the following:

- 1% of the number of shares of our common stock then outstanding, which will equal approximately shares immediately after this offering; or

- the average weekly trading volume of our common stock on The NASDAQ Global Market during the four calendar weeks preceding the filing of a notice on Form 144 with respect to the sale.

At the expiration of the one-year holding period, a person who was not one of our affiliates at any time during the three months preceding a sale would be entitled to sell an unlimited number of shares of our common stock without restriction. A person who was one of our affiliates at any time during the three months preceding a sale would remain subject to the volume restrictions described above.

Sales under Rule 144 by our affiliates are also subject to manner of sale provisions and notice requirements and to the availability of current public information about us.

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Rule 701

In general, under Rule 701, any of our employees, directors, officers, consultants or advisors who purchased shares from us in connection with a compensatory stock or option plan or other written agreement before the effective date of this offering, or who purchased shares from us after that date upon the exercise of options granted before that date, are eligible to resell such shares in reliance upon Rule 144 beginning 90 days after the date of this prospectus. If such person is not an affiliate, the sale may be made subject only to the manner-of-sale restrictions of Rule 144. If such a person is an affiliate, the sale may be made under Rule 144 without compliance with its one-year minimum holding period, but subject to the other Rule 144 restrictions.

Registration Rights

Prior to the closing of this offering, we will enter into a registration rights agreements with DB Holdings and an investor rights agreement with Gulfport. Under these agreements, each of DB Holdings and Gulfport has demand and piggyback registration rights. The demand rights enable each such stockholder to require us to register its shares of our common stock with the SEC at any time, subject to the 180-day lock-up agreement it has entered into in connection with this offering. The piggyback rights will allow each such stockholder to register the shares of our common stock that it owns along with any shares that we register with the SEC. These registration rights are subject to customary conditions and limitations, including the right of the underwriters of an offering to limit the number of shares.

Stock Plans

We intend to file one or more registration statements on Form S-8 under the Securities Act to register shares of our common stock issued or reserved for issuance under our equity incentive plan. The first such registration statement is expected to be filed soon after the date of this prospectus and will automatically become effective upon filing with the SEC. Accordingly, shares registered under such registration statement will be available for sale in the open market following the effective date, unless such shares are subject to vesting restrictions with us, Rule 144 restrictions applicable to our affiliates or the lock-up restrictions described below.

Lock-Up Agreements

We, each of our directors and executive officers, DB Holdings and Gulfport have agreed that, subject to certain exceptions, without the prior written consent of Credit Suisse Securities (USA) LLC, we and they will not, directly or indirectly, for a period of 180 days after the date of the offering (a period that may be extended for up to 18 days under certain circumstances), offer, pledge, sell, contract to sell or otherwise transfer or dispose of any shares of our common stock (other than the shares of our common stock subject to this offering) or any other securities convertible into or exercisable or exchangeable for our common stock. For additional information, see *Underwriting* beginning on page 133 of this prospectus.

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MATERIAL U.S. FEDERAL INCOME AND ESTATE TAX CONSIDERATIONS FOR NON-U.S. HOLDERS

The following is a general discussion of material U.S. federal income and estate tax consequences of the ownership and disposition of our common stock by a non-U.S. holder (as defined below). This discussion deals only with common stock purchased in this offering that is held as a capital asset within the meaning of Section 1221 of the Internal Revenue Code of 1986, as amended, or the Code (generally, property held for investment), by a non-U.S. holder. Except as modified for estate tax purposes, the term non-U.S. holder means a beneficial owner of our common stock that is not a U.S. person or a partnership for U.S. federal income and estate tax purposes. A U.S. person is any of the following:

- an individual who is a citizen or resident of the United States;
- a corporation (including any entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate whose income is subject to U.S. federal income taxation regardless of its source; or
- a trust, if a court within the United States is able to exercise primary supervision over the administration of the trust and one or more U.S. persons have authority to control all substantial decisions of the trust, or if it has a valid election in effect under applicable U.S. Treasury Regulations to be treated as a U.S. person.

An individual may generally be treated as a resident of the United States in any calendar year for U.S. federal income tax purposes, by, among other ways, being present in the United States for at least 31 days in that calendar year and for an aggregate of at least 183 days during a three-year period ending in the current calendar year. For purposes of the 183-day calculation, all of the days present in the current year, one-third of the days present in the immediately preceding year and one-sixth of the days present in the second preceding year are counted. Residents are taxed for U.S. federal income tax purposes as if they were U.S. citizens.

This discussion is based upon provisions of the Code, and Treasury Regulations, administrative rulings and judicial decisions, all as of the date hereof. Those authorities may be changed, perhaps retroactively, so as to result in U.S. federal income and estate tax consequences different from those discussed below. No ruling has been or will be sought from the Internal Revenue Service, or IRS, with respect to the matters discussed below, and there can be no assurance the IRS will not take a contrary position regarding the tax consequences of the acquisition, ownership or disposition of our common stock, or that such contrary position would not be sustained by a court. This discussion does not address all aspects of U.S. federal income and estate taxation and does not deal with other U.S. federal tax laws (such as gift tax laws) or foreign, state, local or other tax considerations that may be relevant to non-U.S. holders in light of their personal circumstances. In addition, this discussion does not address tax considerations applicable to investors that may be subject to special treatment under the U.S. federal income tax laws, such as (without limitation):

- certain former U.S. citizens or residents;
- shareholders that hold our common stock as part of a straddle, constructive sale transaction, synthetic security, hedge, conversion transaction or other integrated investment or risk reduction transaction;
- shareholders that acquired our common stock through the exercise of employee stock options or otherwise as compensation or through a tax-qualified retirement plan;
- shareholders that are partnerships or entities treated as partnerships for U.S. federal income tax purposes or other pass-through entities or owners thereof;

shareholders that own, or are deemed to own, more than five percent (5%) of our outstanding common stock (except to the extent specifically set forth below);

shareholders subject to the alternative minimum tax;

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- financial institutions, banks and thrifts;
- insurance companies;
- tax-exempt entities;
- real estate investment trusts;
- controlled foreign corporations, passive foreign investment companies or corporations that accumulate earnings to avoid U.S. federal income tax;
- broker-dealers or dealers in securities or foreign currencies; and
- traders in securities that use a mark-to-market method of accounting for U.S. federal income tax purposes.

If a partnership (including an entity treated as a partnership for U.S. federal income tax purposes) holds our common stock, the U.S. federal income tax treatment of a partner generally will depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership (including an entity treated as a partnership for U.S. federal income tax purposes) holding our common stock, you should consult your tax advisor.

THIS DISCUSSION IS FOR GENERAL INFORMATION ONLY AND SHOULD NOT BE VIEWED AS TAX ADVICE. INVESTORS CONSIDERING THE PURCHASE OF OUR COMMON STOCK SHOULD CONSULT THEIR OWN TAX ADVISORS REGARDING THE APPLICATION OF THE U.S. FEDERAL INCOME AND ESTATE AND GIFT TAX LAWS TO THEIR PARTICULAR SITUATION AS WELL AS THE APPLICABILITY AND EFFECT OF ANY STATE, LOCAL OR FOREIGN TAX LAWS OR TAX TREATIES AND ANY OTHER U.S. FEDERAL TAX LAWS.

Distributions on Common Stock

We do not expect to pay any cash distributions on our common stock in the foreseeable future. However, in the event we do make such cash distributions, these distributions generally will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. If any such distribution exceeds our current and accumulated earnings and profits, the excess will be treated as a non-taxable return of capital to the extent of the non-U.S. holder s tax basis in our common stock and thereafter as capital gain from the sale or exchange of such common stock. See *Gain on Disposition of Common Stock* below. Dividends paid to a non-U.S. holder of our common stock that are not effectively connected with the non-U.S. holder s conduct of a trade or business within the United States will be subject to U.S. withholding tax at a 30% rate, or if an income tax treaty applies, a lower rate specified by the treaty. In order to receive a reduced treaty rate, a non-U.S. holder must provide to us or our withholding agent IRS Form W-8BEN (or applicable substitute or successor form) properly certifying eligibility for the reduced rate. Non-U.S. holders that do not timely provide us or our withholding agent with the required certification, but that qualify for a reduced treaty rate, may obtain a refund of any excess amounts withheld by timely filing an appropriate claim for refund with the IRS. Non-U.S. holders should consult their tax advisors regarding their entitlement to benefits under an applicable income tax treaty.

Dividends that are effectively connected with a non-U.S. holder s conduct of a trade or business in the United States and, if an income tax treaty so requires, are attributable to a permanent establishment maintained by the non-U.S. holder in the United States, are taxed on a net income basis at the regular graduated rates and in the manner applicable to U.S. persons. In that case, we or our withholding agent will not have to withhold U.S. federal withholding tax if the non-U.S. holder complies with applicable certification and disclosure requirements (which may generally be met by providing an IRS Form W-8ECI). In addition, a branch profits tax may be imposed at a 30% rate (or a lower rate specified under an applicable income tax treaty) on a foreign corporation s effectively connected earnings and profits for the taxable year, as adjusted for certain items. Non-U.S. holders should consult any applicable income tax treaties that may provide for different rules.

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Gain on Disposition of Common Stock

Subject to the discussion below regarding backup withholding, a non-U.S. holder generally will not be subject to U.S. federal income tax on gain recognized on a disposition of our common stock unless:

- the gain is effectively connected with the non-U.S. holder s conduct of a trade or business in the United States and, if an income tax treaty applies, is attributable to a permanent establishment maintained by the non-U.S. holder in the United States, in which case, the gain will be taxed on a net income basis at the U.S. federal income tax rates and in the manner applicable to U.S. persons, and if the non-U.S. holder is a foreign corporation, the branch profits tax described above may also apply;

- the non-U.S. holder is an individual who is present in the United States for 183 days or more in the taxable year of the disposition and meets other requirements, in which case, the non-U.S. holder will be subject to a flat 30% tax on the gain derived from the disposition (or such lower rate specified by an applicable income tax treaty), which may be offset by U.S. source capital losses, provided the non-U.S. holder has timely filed U.S. federal income tax returns with respect to such losses; or

- we are or have been a United States real property holding corporation , or USRPHC, for U.S. federal income tax purposes at any time during the shorter of the five-year period ending on the date of disposition or the period that the non-U.S. holder held our common stock.

Generally, a corporation is a USRPHC if the fair market value of its United States real property interests equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. We have not determined whether we are currently a USRPHC for U.S. federal income tax purposes, but we believe we currently may be a USRPHC. If we are or become a USRPHC, a non-U.S holder nonetheless will not be subject to U.S. federal income tax or withholding in respect of any gain realized on a sale or other disposition of our common stock so long as (i) our common stock is regularly traded on an established securities market for U.S. federal income tax purposes and (ii) such non-U.S. holder does not actually or constructively own, at any time during the applicable period described in the third bullet point, above, more than 5% of our outstanding common stock. We expect our common stock to be regularly traded on an established securities market, although we cannot guarantee it will be so traded. Accordingly, a non-U.S holder who actually or constructively owns more than 5% of our common stock would be subject to U.S. federal income tax and withholding in respect of any gain realized on any sale or other disposition of common stock (taxed in the same manner as gain that is effectively connected income, except that the branch profits tax would not apply). Non-U.S. holders should consult their own advisor about the consequences that could result if we are, or become, a USRPHC.

Information Reporting and Backup Withholding Tax

Dividends paid to you will generally be subject to information reporting and may be subject to U.S. backup withholding. You will be exempt from backup withholding if you properly provide a Form W-8BEN certifying under penalties of perjury that you are a non-U.S. holder or otherwise meet documentary evidence requirements for establishing that you are a non-U.S. holder, or you otherwise establish an exemption. Copies of the information returns reporting such dividends and the tax withheld with respect to such dividends also may be made available to the tax authorities in the country in which you reside.

The gross proceeds from the disposition of our common stock may be subject to information reporting and backup withholding. If you receive payments of the proceeds of a disposition of our common stock to or through a U.S. office of a broker, the payment will be subject to both U.S. backup withholding and information reporting unless you properly provide an IRS Form W-8BEN certifying under penalties of perjury that you are a non-U.S. person (and the payor does not have actual knowledge or reason to know that you are a U.S. person) or you otherwise establish an exemption. If you sell your common stock outside the United States through a non-U.S. office of a non-U.S. broker and the sales proceeds are paid to you outside the United States, then the U.S. backup withholding and information reporting requirements generally will not apply to that payment. However, U.S.

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information reporting, but not backup withholding, will generally apply to a payment of sales proceeds, even if that payment is made outside the United States, if you sell your common stock through a non-U.S. office of a broker that has certain relationships with the United States unless the broker has documentary evidence in its files that you are a non-U.S. person and certain other conditions are met, or you otherwise establish an exemption.

Backup withholding is not an additional tax. You may obtain a refund or credit of any amounts withheld under the backup withholding rules that exceed your U.S. federal income tax liability, if any, provided the required information is timely furnished to the IRS.

Additional Withholding Requirements

Withholding taxes may apply to certain types of payments made to foreign financial institutions (as defined in the Code) and certain other non-U.S. entities. Specifically, the relevant withholding agent may be required to withhold 30% of any dividends and the proceeds of a sale or other disposition of our common stock paid to (i) a foreign financial institution unless such foreign financial institution undertakes certain diligence and reporting and enters into an agreement with the IRS requiring, among other things, that it undertake to identify accounts held by certain U.S. persons or U.S. owned foreign entities, annually report certain information about such accounts, and withhold 30% on payments to non-compliant foreign financial institutions and certain other account holders or (ii) a non-financial foreign entity that is the beneficial owner of the payment unless such entity certifies that it does not have any substantial United States owners or provides the name, address and taxpayer identification number of each substantial United States owner and such entity meets certain other requirements.

Although these rules currently apply to applicable payments made after December 31, 2012, the IRS has issued Proposed Treasury Regulations providing that withholding will only be made on payments of dividends made on or after January 1, 2014, and on other withholdable payments (including payments of gross proceeds) made on or after January 1, 2015. The Proposed Treasury Regulations described above will not be effective until they are issued in their final form, and as of the date of this prospectus, it is not possible to determine whether the proposed regulations will be finalized in their current form or at all. Prospective investors should consult their tax advisors regarding these withholding provisions.

Federal Estate Tax

Our common stock that is owned (or treated as owned) by an individual who is not a citizen or resident of the United States (as specially defined for U.S. federal estate tax purposes) at the time of death will be included in such individual s gross estate for U.S. federal estate tax purposes, unless an applicable estate tax treaty provides otherwise, and, therefore, may be subject to U.S. federal estate tax.

UNDERWRITING

Under the terms and subject to the conditions contained in an underwriting agreement dated , 2012 we and the selling stockholders have agreed to sell to the underwriters named below, for whom Credit Suisse Securities (USA) LLC is acting as representative, the following respective numbers of shares of common stock:

Underwriter	Number of Shares
Credit Suisse Securities (USA) LLC	
Total	

The underwriting agreement provides that the underwriters are obligated to purchase all the shares of common stock in the offering if any are purchased, other than those shares covered by the option described below. The underwriting agreement also provides that if an underwriter defaults, the purchase commitments of non-defaulting underwriters may be increased or the offering may be terminated.

We and the selling stockholders have granted to the underwriters a 30-day option to purchase on a pro rata basis up to an aggregate of additional shares at the initial public offering price less the underwriting discounts and commissions. The option may be exercised only to cover any over-allotments of common stock.

The underwriters propose to offer the shares of common stock initially at the public offering price on the cover page of this prospectus and to selling group members at that price less a selling concession of $ per share. The underwriters and selling group members may allow a discount of $ per share on sales to other broker/dealers. After the initial public offering the representatives may change the public offering price and concession and discount to broker/dealers. The offering of the shares by the underwriters is subject to receipt and acceptance and subject to the underwriters right to reject any order in whole or in part.

The following table summarizes the compensation and estimated expenses we and the selling stockholders will pay:

	Per Share		Total	
	Without Over-allotment	With Over-allotment	Without Over-allotment	With Over-allotment
Underwriting Discounts and Commissions paid by us	$	$	$	$
Expenses payable by us	$	$	$	$
Underwriting Discounts and Commissions paid by selling stockholders	$	$	$	$

We estimate that our out of pocket expenses for this offering will be approximately $. We have agreed to pay expenses incurred by the selling stockholders in connection with this offering other than the underwriting discounts and commissions.

The representative has informed us that it does not expect sales to accounts over which the underwriters have discretionary authority to exceed 5% of the shares of common stock being offered.

We have agreed that, subject to certain exceptions, we will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, or file with the Securities and Exchange Commission a registration statement under the Securities Act relating to any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, or publicly disclose the intention to make any offer, sale, pledge, disposition or filing, without the prior written consent of Credit Suisse Securities (USA) LLC for a period of 180 days after the date of this prospectus. However, in the event that either (1) during the last 17 days of the lock-up period, we release earnings results or material news or a material event relating to us occurs or (2) prior to the expiration of the lock-up period, we announce that we will release earnings results during the 16-day period beginning on the last day of the lock-up period, then in either case the expiration of the lock-up will be extended until the expiration of the 18-day period beginning on the date of the release of the earnings results or the occurrence of the material news or event, as applicable, unless Credit Suisse Securities (USA) LLC waives, in writing, such an extension.

Our officers and directors and the selling stockholders have agreed that, subject to certain exceptions, they will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, enter into a transaction that would have the same effect, or enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of our common stock, whether any of these transactions are to be settled by delivery of our common stock or other securities, in cash or otherwise, or publicly disclose the intention to make any offer, sale, pledge or disposition, or to enter into any transaction, swap, hedge or other arrangement, without, in each case, the prior written consent of Credit Suisse Securities (USA) LLC for a period of 180 days after the date of this prospectus. However, in the event that either (1) during the last 17 days of the lock-up period, we release earnings results or material news or a material event relating to us occurs or (2) prior to the expiration of the lock-up period, we announce that we will release earnings results during the 16-day period beginning on the last day of the lock-up period, then in either case the expiration of the lock-up will be extended until the expiration of the 18-day period beginning on the date of the release of the earnings results or the occurrence of the material news or event, as applicable, unless Credit Suisse Securities (USA) LLC waives, in writing, such an extension.

Credit Suisse Securities (USA) LLC, in its sole discretion, may release the common stock and other securities subject to the lock-up agreements described above in whole or in part at any time. When determining whether or not to release the common stock and other securities from lock-up agreements, Credit Suisse Securities (USA) LLC will consider, among other factors, the holder s reasons for requesting the release and the number of shares of common stock or other securities for which the release is being requested.

The underwriters have reserved for sale at the initial public offering price up to shares of the common stock for employees, directors and other persons associated with us who have expressed an interest in purchasing common stock in the offering. The number of shares available for sale to the general public in the offering will be reduced to the extent these persons purchase the reserved shares. Any reserved shares not so purchased will be offered by the underwriters to the general public on the same terms as the other shares.

We and the selling stockholders have agreed to indemnify the underwriters against liabilities under the Securities Act, or contribute to payments that the underwriters may be required to make in that respect.

We have applied to list the shares of our common stock on The NASDAQ Global Market under the symbol FANG .

In connection with the listing of our common stock on The NASDAQ Global Market, the underwriters will undertake to sell round lots of 100 shares or more to a minimum of 400 beneficial owners.

Prior to this offering, there has been no public market for our common stock. The initial public offering price for our common stock will be determined by negotiation between us, the selling stockholders and the underwriters. The principal factors to be considered in determining the initial public offering price include the following:

- the general condition of the securities markets;

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- market conditions for initial public offerings;
- the market for securities of companies in businesses similar to ours;
- the history and prospects for the industry in which we compete;
- our past and present operations and earnings and our current financial position;
- the history and prospects for our business;
- an assessment of our management; and
- other information included in this prospectus and otherwise available to the underwriters.

We cannot assure you that the initial public offering price will correspond to the price at which our common stock will trade in the public market subsequent to this offering or that an active trading market will develop and continue after this offering.

Certain of the underwriters and their respective affiliates have from time to time performed, and may in the future perform, various financial advisory, commercial banking and investment banking services for us and for our affiliates in the ordinary course of business for which they have received and would receive customary compensation.

In connection with the offering the underwriters may engage in stabilizing transactions, over-allotment transactions, syndicate covering transactions and penalty bids in accordance with Regulation M under the Exchange Act.

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.
- Over-allotment involves sales by the underwriters of shares in excess of the number of shares the underwriters are obligated to purchase, which creates a syndicate short position. The short position may be either a covered short position or a naked short position. In a covered short position, the number of shares over-allotted by the underwriters is not greater than the number of shares that they may purchase in the over-allotment option. In a naked short position, the number of shares involved is greater than the number of shares in the over-allotment option. The underwriters may close out any covered short position by either exercising their over-allotment option and/or purchasing shares in the open market.
- Syndicate covering transactions involve purchases of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions. In determining the source of shares to close out the short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through the over-allotment option. If the underwriters sell more shares than could be covered by the over-allotment option, a naked short position, the position can only be closed out by buying shares in the open market. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

Penalty bids permit the representative to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of the common stock. As a result the price of our common stock may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the NASDAQ Global Market or otherwise and, if commenced, may be discontinued at any time.

A prospectus in electronic format may be made available on the web sites maintained by one or more of the underwriters, or selling group members, if any, participating in this offering and one or more of the underwriters participating in this offering may distribute prospectuses electronically. The representative may agree to allocate a number of shares to underwriters and selling group members for sale to their online brokerage account holders. Internet distributions will be allocated by the underwriters and selling group members that will make internet distributions on the same basis as other allocations.

European Economic Area

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each such state being referred to herein as a Relevant Member State), each underwriter has represented and agreed that with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (each such date being referred to herein as a Relevant Implementation Date) it has not made and will not make an offer of shares to the public in that Relevant Member State prior to the publication of a prospectus in relation to the shares which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the Prospectus Directive, except that it may, with effect from and including the Relevant Implementation Date, make an offer of shares to the public in that Relevant Member State at any time:

(a) to legal entities which are authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities;

(b) to any legal entity which has two or more of (1) an average of at least 250 employees during the last financial year; (2) a total balance sheet of more than 43,000,000 and (3) an annual net turnover of more than 50,000,000, as shown in its last annual or consolidated accounts;

(c) to fewer than 100 natural or legal persons (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the representatives for any such offer; or

(d) in any other circumstances which do not require the publication by the Company of a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an offer of shares to the public in relation to any shares in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the shares to be offered so as to enable an investor to decide to purchase or subscribe the shares, as the same may be varied in that Relevant Member State by any measure implementing the Prospectus Directive in that Relevant Member State and the expression Prospectus Directive means Directive 2003/71/EC and includes any relevant implementing measure in each Relevant Member State.

United Kingdom

Each underwriter has represented and agreed that:

(a) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the Financial Services and Markets Act 2000, or the FSMA, received by it in connection with the issue or sale of the shares in circumstances in which Section 21(1) of the FSMA does not apply to the Company; and

(b) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the shares in, from or otherwise involving the United Kingdom.

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Hong Kong

The shares may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to professional investors within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a prospectus within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation or document relating to the shares may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to shares which are or are intended to be disposed of only to persons outside Hong Kong or only to professional investors within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

Singapore

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the shares may not be circulated or distributed, nor may the shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore, or the SFA, (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the shares are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the shares under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

Japan

The securities have not been and will not be registered under the Financial Instruments and Exchange Law of Japan, or the Financial Instruments and Exchange Law, and each underwriter has agreed that it will not offer or sell any securities, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

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LEGAL MATTERS

The validity of the shares of common stock that are offered hereby by us and the selling stockholders will be passed upon by Akin Gump Strauss Hauer & Feld LLP. The underwriters have been represented by Latham & Watkins LLP, Houston, Texas.

EXPERTS

The audited financial statements included in this prospectus and elsewhere in the registration statement have been so included in reliance upon the reports of Grant Thornton LLP, independent registered public accountants, upon the authority of said firm as experts in accounting and auditing.

Information referenced in this prospectus regarding our estimated quantities of oil and gas reserves and the discounted present value of future net cash flows therefrom is based upon estimates of such reserves and present values prepared by Ryder Scott Company L.P. as of December 31, 2011 and by Pinnacle Energy Services, LLC as of December 31, 2010 and 2009, each an independent petroleum engineering firm. Information referenced in this prospectus regarding estimated quantities of oil and gas reserves and the discounted present value of future net cash flows attributable to the Windsor UT properties and the properties subject to the Gulfport contribution is based upon estimates of such reserves and present values prepared in each case by Ryder Scott Company L.P. as of December 31, 2011.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 under the Securities Act covering the securities offered by this prospectus, which constitutes a part of that registration statement. Items included in the registration statement as Part II are omitted from this prospectus in accordance with the rules and regulations of the SEC. For further information about us and the common stock offered by this prospectus, reference is made to the registration statement and the exhibits filed with the registration statement. Statements contained in this prospectus and any prospectus supplement as to the contents of any contract or other document referred to are qualified by reference to each such contract or document filed as part of the registration statement. When we complete this offering, we will be required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read any materials we file with the SEC free of charge at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Copies of all or any part of these documents may be obtained from such office upon the payment of the fees prescribed by the SEC. The public may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC. The address of the site is www.sec.gov. The registration statement, including all exhibits thereto and amendments thereof, has been filed electronically with the SEC.

Appendix A

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 in this prospectus.

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 prospectus in reference to crude oil or other liquid hydrocarbons.

Bbl/day. Bbl per day.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

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.

Environmental Assessment (EA). A study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.

Environmental Impact Statement (EIS). A more detailed study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project that may be made available to the public for review and comment.

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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/day. Mcf per day.

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

MMBbls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcf/day. MMcf per day.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/day. MMcfe per day.

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.

PDNP. Proved developed non-producing.

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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 (PDP). 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 (PUD). 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 gas sands. 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.

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Appendix B

WINDSOR PERMIAN LLC

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2011

/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

[SEAL]

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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January 20, 2012

Windsor Permian LLC

500 West Texas, Suite 1210

Midland, Texas 79701

Gentlemen:

At your request, Ryder Scott Company (Ryder Scott) has prepared an estimate of the proved, probable and possible reserves, future production, and income attributable to certain leasehold interests of Windsor Permian LLC (Windsor) as of December 31, 2011. 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 20, 2012 and presented herein, was prepared for public disclosure in Windsor 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, probable and possible liquid hydrocarbon reserves and 100 percent of the total net proved, probable and possible gas reserves of Windsor as of December 31, 2011.

The results of this study are summarized below.

SEC PARAMETERS

Estimated Net Reserves and Income Data

Certain Leasehold Interests of **Windsor**

Permian LLC

As of December 31, 2011

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate MBbl	3,494	311	12,912	16,717
Plant Products MBbl	1,143	90	3,530	4,763
Gas MMCF	4,799	388	14,432	19,619
MBOE	5,437	466	18,847	24,750
Income Data ($M)				
Future Gross Revenue	$ 386,409	$ 33,732	$ 1,383,530	$ 1,803,671
Deductions	115,007	10,909	706,774	832,690
Future Net Income (FNI)	$ 271,402	$ 22,823	$ 676,756	$ 970,981
Discounted FNI @ 10%	$ 147,447	$ 12,090	$ 183,910	$ 343,447

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

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	Total Probable Undeveloped	Total Possible Undeveloped
Net Remaining Reserves		
Oil/Condensate MBbl	14,309	4,892
Plant Products MBbl	3,058	1,024
Gas MMCF	11,133	3,577
MBOE	19,223	6,512
Income Data ($M)		
Future Gross Revenue	$ 1,470,059	$ 500,339
Deductions	827,874	283,474
Future Net Income (FNI)	$ 642,185	$ 216,865
Discounted FNI @ 10%	$ 134,064	$ 42,956

The estimated reserves and future net income amounts presented in this report, as of December 31, 2011 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 Aries™ System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used solely at the request of Windsor. 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 96.0 percent and gas reserves account for the remaining 4.0 percent of total future gross revenue from proved reserves. Liquid hydrocarbon reserves account

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January 20, 2012

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for approximately 97.2 percent and gas reserves account for the remaining 2.8 percent of total future gross revenue from probable reserves. Liquid hydrocarbon reserves account for approximately 97.3 percent and gas reserves account for the remaining 2.7 percent of total future gross revenue from possible 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, 2011 ($M)		
Discount Rate Percent	**Total Proved**	**Total Probable**	**Total Possible**
5	$539,390	$283,594	$93,201
15	$236,843	$ 59,858	$18,649
20	$171,787	$ 18,984	$ 5,580
25	$128,974	$ -4,953	$ -1,903

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, probable and possible 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 category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible 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 Windsor s request, this report addresses the proved, probable and possible 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. 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. Possible reserves are those additional reserves which are less certain to be recovered than probable reserves and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserve categories that are included herein have not been adjusted to reflect these varying degrees of risk associated with them and thus are not comparable.

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, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved, probable and possible 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.

Windsor 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, probable and possible reserves actually recovered and amounts of proved, probable and possible 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 Windsor 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, probable and possible 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 December, 2011 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Windsor 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, probable, and possible developed non-producing and undeveloped reserves included herein were estimated by the analogy method.

To estimate economically recoverable proved, probable and possible 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, probable and possible 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.

Windsor 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, probable and possible production and income, we have relied upon data furnished by Windsor 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 Windsor. 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, probable and possible 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, probable and possible 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 Windsor. 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.

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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, Windsor furnished us with the average prices in effect on December 31, 2011. 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 Windsor 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 Windsor 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**	**Avg Probable Realized Prices**	**Avg Possible Realized Prices**
North America						
United States	Oil/Condensate	WTI Cushing	$ 96.19/Bbl	$ 93.09/Bbl	$ 92.89/Bbl	$ 92.85/Bbl
	NGLs	WTI Cushing	$ 61.97/Bbl	$ 56.33/Bbl	$ 57.02/Bbl	$ 56.91/Bbl
	Gas	Henry Hub/ Colorado Interstate	$ 4.12/MMBTU	$ 3.91/MCF	$ 3.95/MCF	$ 3.95/MCF

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

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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Costs

Operating costs for the leases and wells in this report are based on the operating expense reports of Windsor 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 Windsor. 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 Windsor 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. Windsor 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 Windsor s estimate.

The proved, probable and possible developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Windsor s plans to develop these reserves as of December 31, 2011. The implementation of Windsor s development plans as presented to us and incorporated herein is subject to the approval process adopted by Windsor s management. As the result of our inquiries during the course of preparing this report, Windsor has informed us that the development activities included herein have been subjected to and received the internal approvals required by Windsor 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 Windsor. Additionally, Windsor 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 Windsor 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 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

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Windsor Permian LLC

January 20, 2012

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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 Windsor. 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 Windsor.

We have provided Windsor 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 Windsor 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/pl

[SEAL]

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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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 2011 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.

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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.

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PETROLEUM RESERVES DEFINITIONS

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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.

(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.

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PETROLEUM RESERVES DEFINITIONS

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PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(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.

PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

Probable reserves. *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.*

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

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POSSIBLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(17) defines possible oil and gas reserves as follows:

Possible reserves. *Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.*

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

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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;

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RESERVES STATUS DEFINITIONS AND GUIDELINES

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(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.

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Appendix C

WINDSOR UT, LLC

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2011

Don P. Griffin, P.E.

TBPE License No. 64150

Senior Vice President

RYDER SCOTT COMPANY, L.P.

TBPE Firm License No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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January 20, 2012

Windsor UT, LLC

500 West Texas, Suite 1210

Midland, Texas 79701

Gentlemen:

At your request, Ryder Scott Company (Ryder Scott) has prepared an estimate of the proved and probable reserves, future production, and income attributable to certain leasehold interests of Windsor UT (Windsor) as of December 31, 2011. 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 20, 2012 and presented herein, was prepared for public disclosure in Windsor 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 and probable liquid hydrocarbon reserves and 100 percent of the total net proved and probable gas reserves of Windsor as of December 31, 2011.

The results of this study are summarized below.

SEC PARAMETERS

Estimated Net Reserves and Income Data

Certain Leasehold Interests of

Windsor UT, LLC

As of December 31, 2011

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate MBbl	109	34	1,240	1,383
Plant Products MBbl	23	7	256	286
Gas MMCF	76	23	834	933
MBOE	145	45	1,635	1,825
Income Data ($M)				
Future Gross Revenue	$ 11,199	$ 3,512	$ 126,439	$ 141,150
Deductions	3,327	1,561	70,584	75,472
Future Net Income (FNI)	$ 7,872	$ 1,951	$ 55,855	$ 65,678
Discounted FNI @ 10%	$ 4,449	$ 829	$ 12,730	$ 18,008

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

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		Total Probable Undeveloped
Net Remaining Reserves		
Oil/Condensate MBbl		2,583
Plant Products MBbl		533
Gas MMCF		1,737
MBOE		3,406
Income Data ($M)		
Future Gross Revenue	$	263,414
Deductions		147,050
Future Net Income (FNI)	$	116,364
Discounted FNI @ 10%	$	18,984

The estimated reserves and future net income amounts presented in this report, as of December 31, 2011 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 Aries™ System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used solely at the request of Windsor. 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

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Windsor UT, LLC

January 20, 2012

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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 97.5 percent and gas reserves account for the remaining 2.5 percent of total future gross revenue from proved reserves. Liquid hydrocarbon reserves account for approximately 97.5 percent and gas reserves account for the remaining 2.5 percent of total future gross revenue from probable 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.

Discount Rate	Discounted Future Net Income As of December 31, 2011 ($M)	
Percent	Total Proved	Total Probable
5	$ 32,528	$ 45,247
15	$ 10,383	$ 7,624
20	$ 5,895	$ 2,283
25	$ 3,054	$ -309

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 and probable 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 category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved and probable 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

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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 Windsor s request, this report addresses the proved and probable 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. 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. Possible reserves are those additional reserves which are less certain to be recovered than probable reserves and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved and probable based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserve categories that are included herein have not been adjusted to reflect these varying degrees of risk associated with them and thus are not comparable.

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, probable and possible reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved and probable 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.

Windsor 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 and probable reserves actually recovered and amounts of proved and probable income actually received to differ significantly from the estimated quantities.

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The estimates of reserves presented herein were based upon a detailed study of the properties in which Windsor 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.

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The proved and probable 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 December, 2011 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Windsor 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 and probable developed non-producing and undeveloped reserves included herein were estimated by the analogy method**.**

To estimate economically recoverable proved, probable and possible 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, probable and possible 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.

Windsor 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 and probable production and income, we have relied upon data furnished by Windsor 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 Windsor. 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 and probable 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 and probable 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 Windsor. 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, Windsor furnished us with the average prices in effect on December 31, 2011. 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.

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January 20, 2012

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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 Windsor 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 Windsor 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	Avg Probable Realized Prices
North America United States	Oil/Condensate	WTI Cushing	$96.19/Bbl	$92.99/Bbl	$92.99/Bbl
	NGLs	WTI Cushing	$61.97/Bbl	$56.74/Bbl	$56.74/Bbl
	Gas	Henry Hub/ Colorado Interstate	$4.12/MMBTU	$3.92/MCF	$3.92/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 Windsor 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 Windsor. 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 Windsor 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. Windsor 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 Windsor s estimate.

The proved and probable developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Windsor s plans to develop these reserves as of December 31, 2011. The implementation of Windsor s development plans as presented to us and incorporated herein is subject to the approval process adopted by Windsor s management. As the result of our inquiries during the course of preparing this report, Windsor has informed us that the development activities included herein have been subjected to and received the internal approvals required by Windsor 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 Windsor. Additionally, Windsor 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 Windsor 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 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 Windsor. 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 Windsor.

We have provided Windsor 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 Windsor 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

Don P. Griffin, P.E.

TBPE License No. 64150

Senior Vice President

DPG/pl

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RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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 2011 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.

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RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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

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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

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(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.

(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.

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PROBABLE RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(18) defines probable oil and gas reserves as follows:

Probable reserves. *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.*

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

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RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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.

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RESERVES STATUS DEFINITIONS AND GUIDELINES

Page 2

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.

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Appendix D

GULFPORT ENERGY CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2011

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

[SEAL]

RYDER SCOTT COMPANY, L.P.

TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235 TELEPHONE(713) 651-9191

January 13, 2012

Gulfport Energy Corporation

14313 N. May, Suite 100

Oklahoma City, Oklahoma 73134

Gentlemen:

At your request, Ryder Scott Company (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of Gulfport Energy Corporation (Gulfport) as of December 31, 2011. 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 6, 2012, and presented herein, was prepared for public disclosure by Gulfport in 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 Gulfport as of December 31, 2011.

The results of this study are summarized below.

SEC PARAMETERS

Estimated Net Reserves and Income Data

Certain Leasehold Interests of

Gulfport Energy Corporation

As of December 31, 2011

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate Mbbl	1,853	244	5,989	8,086
Plant Products Mbbl	660	46	2,085	2,791
Gas MMCF	2,853	197	8,996	12,046
Income Data ($M)				
Future Gross Revenue	$ 210,025	$ 24,859	$ 675,799	$ 910,683
Deductions	52,844	2,238	348,154	403,236
Future Net Income (FNI)	$ 157,181	$ 22,621	$ 327,645	$ 507,447

Discounted FNI @ 10%	$ 84,900	$ 14,551	$ 102,837	$ 202,288

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

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The estimated reserves and future net income amounts presented in this report, as of December 31, 2011, 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 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, 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. 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 Aries™ System Petroleum Economic Evaluation Software, a copyrighted program of Halliburton. The program was used solely at the request of Gulfport. 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 94.9 percent and gas reserves account for the remaining 5.1 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.

Discount Rate	Discounted Future Net Income ($M) As of December 31, 2011
	Total Proved
Percent	
5	$303,812
15	$144,573
20	$108,577
25	$ 84,579

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 definition 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.

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The various proved 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 category.

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 Gulfport s request, this report addresses only 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. The proved reserves included herein were estimated using deterministic methods. 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.

Proved 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.

Gulfport 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 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 proved reserves presented herein were based upon a detailed study of the properties in which Gulfport 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

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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 methods. Approximately 90 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods**.** These performance methods involved decline curve analysis which utilized extrapolations of historical production and pressure data available through October 2011 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Gulfport or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 10 percent of the proved producing reserves were estimated by analogy or a combination of performance and analogy. These methods were 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 of the proved developed non-producing and undeveloped reserves included herein were estimated by the analogy method. The data utilized from the analogues were considered sufficient for the purpose thereof.

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 that 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.

Gulfport 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 Gulfport 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, 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 Gulfport. 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 Gulfport. 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 unweighted arithmetic average as previously described.

Gulfport furnished us with the above mentioned average prices in effect on December 31, 2011. 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 that 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 Gulfport. The differentials 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 data used by Gulfport 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 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	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$ 96.19/Bbl	$ 93.11/Bbl
	NGLs	WTI Cushing	$ 96.19/Bbl	$ 57.09/Bbl
	Gas	Henry Hub Colorado Interstate	$ 4.12/MMBTU	$ 4.04/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 Gulfport 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 Gulfport. 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 Gulfport 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. Gulfport 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 Gulfport s estimate.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Gulfport s plans to develop these reserves as of December 31, 2011. The implementation of Gulfport s development plans as presented to us and incorporated herein is subject to the approval process adopted by Gulfport s management. As the result of our inquiries during the course of preparing this report, Gulfport has informed us that the development activities included herein have been subjected to and received the internal approvals required by Gulfport 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 Gulfport. Additionally, Gulfport 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 Gulfport 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 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 Gulfport. 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 Gulfport.

We have provided Gulfport 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 Gulfport 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

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

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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. As part of his 2009 continuing education hours, Mr. Griffin attended an internally presented 16 hours of formalized training relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Griffin attended an additional 15 hours of training during 2010 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.

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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.

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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.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(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.

(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.

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(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.

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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.

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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.

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INDEX TO FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

Members

Windsor Permian LLC

We have audited the accompanying consolidated balance sheets of Windsor Permian LLC and subsidiaries (collectively the Company) as of December 31, 2011 and 2010, and the related consolidated statements of operations, changes in member s equity, and cash flows for each of the three years in the period ended December 31, 2011. 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 audit 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Windsor Permian LLC and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, the Company adopted the new oil and gas reserve estimation and disclosure requirements as of December 31, 2009.

/s/ Grant Thornton LLP

Oklahoma City, Oklahoma

March 23, 2012

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Windsor Permian LLC and Subsidiaries

Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 6,802,389	$ 4,089,745
Accounts receivable:		
Joint interest and other	3,734,513	3,540,244
Oil and natural gas sales	838,791	305,500
Related party	13,122,589	8,342,033
Inventories	6,006,355	8,433,734
Prepaid expenses and other	428,202	326,148
Total current assets	30,932,839	25,037,404
Property and equipment		
Oil and natural gas properties, at cost, based on the full cost method of accounting ($1,732,329 and $825,742 excluded from amortization at December 31, 2011 and December 31, 2010, respectively)	325,510,080	239,771,620
Other property and equipment	1,016,574	11,915,780
Accumulated depletion, depreciation, amortization and impairment	(119,500,035)	(104,845,670)
	207,026,619	146,841,730
Investments-equity method	10,309,668	
Other assets	1,214,759	637,562
Total assets	$ 249,483,885	$ 172,516,696
Liabilities and Member s Equity		
Current liabilities:		
Accounts payable trade	$ 8,769,491	$ 8,641,089
Accounts payable related party	3,436,195	4,785,810
Accrued capital expenditures	13,922,932	5,387,746
Other accrued liabilities	4,804,069	696,583
Revenues and royalties payable	3,165,267	499,048
Derivative contracts	8,320,351	
Total current liabilities	42,418,305	20,010,276
Note payable credit facility long term	85,000,000	44,766,687
Derivative contracts	6,138,573	1,373,864
Asset retirement obligations	1,079,725	727,826
Total liabilities	134,636,603	66,878,653
Commitments and contingencies (Note 11)		
Member s equity	114,847,282	105,638,043
Total liabilities and member s equity	$ 249,483,885	$ 172,516,696

See accompanying notes to consolidated financial statements.

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Windsor Permian LLC and Subsidiaries

Consolidated Statements of Operations

	Year Ended December 31, 2011	2010	2009
Revenues:			
Oil sales-related party	$ 38,178,686	$ 21,402,799	$ 8,815,681
Oil sales	2,582,019	74,574	973,058
Natural gas sales	1,646,848	1,400,584	922,137
Natural gas liquid sales	4,773,249	3,563,970	2,005,135
Oil and natural gas services-related party	1,490,910	811,247	
Total revenues	48,671,712	27,253,174	12,716,011
Costs and expenses:			
Lease operating expenses	8,218,217	3,039,462	1,551,047
Lease operating expenses-related party	2,127,138	1,549,097	815,576
Production taxes-related party	1,759,601	993,383	406,627
Production taxes	574,252	353,496	256,441
Gathering and transportation	201,828	105,870	42,091
Oil and natural gas services	1,207,101	228,046	
Oil and natural gas services related party	525,791	583,201	
Depreciation, depletion and amortization	15,402,826	8,145,143	3,215,891
General and administrative expenses-related party	3,160,512	2,656,278	4,632,671
General and administrative expenses	442,967	395,349	429,947
Asset retirement obligation accretion expense	63,259	37,856	27,934
Total costs and expenses	33,683,492	18,087,181	11,378,225
Income from operations	14,988,220	9,165,993	1,337,786
Other income (expense)			
Interest income	11,197	34,474	35,075
Interest expense	(2,528,058)	(836,265)	(10,938)
Loss on derivative contracts	(13,009,393)	(147,983)	(4,068,005)
Loss from equity investment	(7,017)		
Total other expense, net	(15,533,271)	(949,774)	(4,043,868)
Net income (loss)	$ (545,051)	$ 8,216,219	$ (2,706,082)
Pro forma information-(unaudited)			
Net income (loss) before income taxes, as reported	$ (545,051)	$ 8,216,219	$ (2,706,082)
Pro forma provision (benefit) for income tax			
Pro forma net (loss) income	$ (545,051)	$ 8,216,219	$ (2,706,082)
Pro forma income (loss) per common share basic and diluted	$		
Weighted average pro forma shares outstanding basic and diluted			

See accompanying notes to consolidated financial statements.

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Windsor Permian LLC and Subsidiaries

Consolidated Statement of Changes in Member s Equity

	Total member s equity
Balance at January 1, 2009	$ 70,615,293
Contributions	16,893,000
Distributions	(600,000)
Net loss	(2,706,082)
Balance at December 31, 2009	84,202,211
Contributions	18,798,613
Distributions	(5,579,000)
Net income	8,216,219
Balance at December 31, 2010	105,638,043
Contributions	9,210,000
Equity based compensation	544,290
Net loss	(545,051)
Balance at December 31, 2011	$ 114,847,282

See accompanying notes to consolidated financial statements.

Windsor Permian LLC and Subsidiaries

Consolidated Statements of Cash Flows

	Year Ended December 31, 2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	$ (545,051)	$ 8,216,219	$ (2,706,082)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Asset retirement obligation accretion expense	63,259	37,856	27,934
Depreciation, depletion, and amortization	15,905,315	8,145,143	3,215,891
Amortization of debt issuance costs	250,010	163,297	10,937
Loss on derivative contracts	13,009,393	147,983	4,068,005
(Gain) loss on sale of assets	(22,942)	(4,675)	1,588
Equity-based compensation expense	544,290		
Changes in operating assets and liabilities:			
Accounts receivable	(1,085,025)	(1,822,949)	592,489
Accounts receivable-related party	(4,780,556)	(6,793,208)	(1,548,825)
Inventories	(871,969)	(4,896,909)	83,048
Prepaid expenses and other	(201,732)	(326,148)	
Accounts payable and accrued liabilities	2,656,836	1,952,645	(597,506)
Accounts payable and accrued liabilities-related party	759,377	(408,892)	(445,913)
Revenues and royalties payable	2,666,219	499,048	
Revenues and royalties payable-related party	2,036,770	266,414	
Net cash provided by operating activities	30,384,194	5,175,824	2,701,566
Cash flows from investing activities:			
Additions to oil and natural gas properties	(58,159,977)	(7,623,975)	(26,622,735)
Additions to oil and natural gas properties-related party	(17,219,632)	(34,849,118)	
Proceeds from sale of oil and natural gas properties		1,250,000	
Purchase of other property and equipment	(7,064,972)	(11,741,073)	(8,856)
Proceeds from sale of property and equipment	54,909	20,075	2,000
Settlement of non-hedge derivative instruments	(4,126,800)	(3,962,440)	(2,770,026)
Receipt (payment) on derivative margins	4,202,467	3,771,890	(2,750,000)
Deconsolidation of Bison	(9,536)		
Proceeds from sale of membership interest in equity investment	6,009,499		
Net cash used in investing activities	(76,314,042)	(53,134,641)	(32,149,617)
Cash flows from financing activities:			
Borrowing on credit facility	40,233,313	61,066,687	7,650,000
Repayment on credit facility		(23,950,000)	
Debt issuance costs	(770,462)	(718,046)	(50,000)
Initial public offering costs	(30,359)		(43,750)
Contributions by members	9,210,000	18,798,613	16,893,000
Distributions by members		(5,579,000)	(600,000)
Net cash provided by financing activities	48,642,492	49,618,254	23,849,250
Net increase (decrease) in cash and cash equivalents	2,712,644	1,659,437	(5,598,801)
Cash and cash equivalents at beginning of period	4,089,745	2,430,308	8,029,109

Cash and cash equivalents at end of period	$ 6,802,389	$ 4,089,745	$ 2,430,308
Supplemental cash flow information			
Interest paid, net of capitalized interest	$ 2,265,005	$ 600,194	$
Asset retirement obligation incurred, including changes in estimate	$ 288,640	$ 208,083	$ 79,666

See accompanying notes to consolidated financial statements.

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Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements

1. Organization

Windsor Permian LLC (Windsor) is a limited liability company formed on October 23, 2007 to acquire, produce, develop and exploit oil and natural gas properties. As a limited liability company, the members of Windsor are not liable for the liabilities or other obligations of Windsor. Windsor is wholly owned by an investment fund which is controlled and managed by Wexford Capital LP (Wexford). Collectively, Windsor and its subsidiaries, Bison Drilling and Field Services LLC (formerly known as Windsor Drilling LLC) through March 31, 2011, and West Texas Field Services LLC, are referred to in these financial statements as the Company .

The Company is engaged in the acquisition, exploitation, development and production of oil and natural gas properties and related sale of oil, natural gas and natural gas liquids. The Company s reserves are located in the Southern region of the United States. The Company s results of operations are largely dependent on the difference between the prices received for its oil, natural gas and natural gas liquids and the cost to find, develop, produce and market such resources. Oil and natural gas prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond the Company s control. These factors include worldwide political instability, quantity of natural gas in storage, foreign supply of oil and natural gas, the price of foreign imports, the level of consumer demand and the price of available alternative fuels, among others.

2. Summary of Significant Accounting Policies

The Company s consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. The consolidated financial statements include the accounts of Windsor and its wholly owned subsidiaries, except for the accounts of Bison Drilling and Field Services LLC, which has been excluded from the Company s consolidated financial statements effective March 31, 2011 (Note 5). All significant intercompany accounts and transactions have been eliminated in consolidation.

Use of estimates

Certain amounts included in or affecting the Company s 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 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 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 reserve quantities and related estimates of the present value of future net revenues, the carrying value of oil and gas properties and asset retirement obligations.

Cash and Cash Equivalents

The Company considers all highly liquid debt instruments purchased with a maturity of three months or less and money market funds to be cash equivalents. The Company utilizes bank deposit accounts which periodically sweep available cash into uninsured short-term investment securities. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on such accounts.

Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

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. As discussed in Note 10, through February 26, 2010 a significant portion of the Company s oil and natural gas properties were contractually operated by an affiliate. Prior to February 26, 2010, purchasers remitted payment for production to the affiliated operator and the affiliated operator, in turn, remitted payment 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, 2011, 2010 and 2009.

Fair Value of Financial Instruments

The Company s financial instruments consist of cash and cash equivalents, receivables, payables, derivatives and note 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. Derivatives are recorded at fair value (see Note 9).

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. General and administrative 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 general and administrative costs not directly associated with exploration and development activities are charged to expense as they are incurred. Capitalized general and administrative costs were $871,036 for the year ended December 31, 2011, and no amounts were capitalized for the years ended December 31, 2010 and 2009. 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). Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The average depletion rate per barrel equivalent unit of production was $25.40, $17.78 and $11.21 for the years ended December 31, 2011, 2010 and 2009, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $15,178,366, $7,373,126 and $3,155,084 for the years ended December 31, 2011, 2010 and 2009, respectively.

Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

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, the Company 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, 2011, 2010 or 2009.

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. The inclusion of the Company s unevaluated costs into the amortization base is expected to be completed within three years.

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 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 $726,949, $772,017 and $60,807 for the years ended December 31, 2011, 2010 and 2009, respectively.

Impairment of Long-Lived Assets

Other long-lived assets, drilling rigs and related 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, 2011, 2010 or 2009.

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, 2010 and 2009, the Company capitalized interest expense totaling $150,280 and $54,322, respectively. During the year ended December 31, 2011, the Company did not capitalize any interest expense.

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Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

Inventories

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

	December 31,	
	2011	**2010**
Tubular goods and equipment	$ 5,630,208	$ 8,269,628
Crude oil	376,147	164,106
	$ 6,006,355	$ 8,433,734

The Company s tubular goods and equipment is primarily comprised of oil and 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, 2011, the Company estimated that all of its tubular goods and equipment will be utilized within one year. The total inventory includes tubular goods in transit of $1,093,708 and $1,377,567 at December 31, 2011 and 2010, respectively. Some of the tubular and casing pipe has been purchased, at cost, from an affiliated company. The Company owed this affiliate $68,875 at December 31, 2010, and did not have an outstanding balance with the affiliated company at December 31, 2011. This amount is included in accounts payable-related party in the consolidated balance sheets.

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 $1,167,621 and $637,562 as of December 31, 2011 and 2010, respectively. The Company includes the unamortized costs in other assets in its 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 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, 2011 and 2010. 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

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Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

is recognized in the statement of operations. However, because substantially all of Bison s earnings are generated by performing services on properties owned and operated by the Company, the Company s share of Bison s earnings has not been recognized but has been credited to oil and gas properties. 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 at December 31, 2011. For additional information on the Company s investments, see Note 5.

Accounting for Equity-Based Compensation

The Company accounts for equity-based compensation in accordance with the provisions of FASB ASC Topic 718, Compensation Stock Compensation (FASB ASC 718). FASB ASC 718 requires equity-based payments to employees to be recognized as expense over the applicable service period based on the fair value of the award on the date of grant.

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 years ended December 31, 2011 and 2010, Windsor Midstream LLC, an entity controlled by Wexford, our equity sponsor, accounted for 78% and 81% of our revenue, respectively. For the year ended December 31, 2009, two purchasers accounted for more than 10% of our revenue: Windsor Midstream LLC (68.3%) and DCP Midstream, LP (14.8%). 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.

Commodity Risk Management

The Company has used energy derivatives for the purpose of mitigating the risk resulting from fluctuations in the market price of crude oil. The Company recognizes all of its 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. For those derivative instruments that are designated and qualify as hedging instruments, the Company designates 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 hedged 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 the Company s derivatives were designated as hedging instruments during the years ended December 31, 2011, 2010 and 2009.

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

The operations of the Company, as limited liability companies, are not subject to federal income taxes. As appropriate, the taxable income or loss applicable to those operations is included in the federal income tax returns

Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

of the respective owners and no income tax effect is included in the accompanying consolidated financial statements. The Company is subject to margin tax in the state of Texas. During the years ended December 31, 2011, 2010 and 2009, there was no margin tax expense. The Company s 2008, 2009 and 2010 federal income tax and state margin tax returns remain open to examination by tax authorities. As of December 31, 2011 and 2010, the Company has 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, 2011, 2010 and 2009, there was no interest or penalties associated with uncertain tax positions in the Company s consolidated financial statements.

Unaudited Pro Forma Income Taxes and Earnings Per Share

Prior to the completion of a proposed 2012 initial public offering of common stock (IPO) by Diamondback Energy, Inc. (Diamondback), all the equity interests in Windsor will be contributed to Diamondback and Windsor will become a wholly-owned subsidiary of Diamondback (Proposed Contribution Transaction). Diamondback, a holding company formed on December 30, 2011 which will not conduct any material business operations prior to the Proposed Contribution Transaction, is a C-Corp under the Internal Revenue Code and is subject to income taxes. Accordingly, the Company computed a pro forma income tax provision as if the Company were a C-Corp for all periods presented. 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. However, on a pro forma basis, management has determined that any net deferred income tax asset would not be realizable; therefore, tax expense would be zero for all periods. Additionally, upon Windsor becoming a subsidiary of Diamondback, the Company will establish a net deferred tax liability for differences between the tax and book basis of the Company s assets and liabilities, and record a corresponding first day tax expense to net income from continuing operations. On a pro forma basis, at December 31, 2011 the amount of this charge would have been approximately $26.2 million.

Also, upon completion of the Proposed Contribution Transaction, the Company will present pro forma earnings per share for the most recent period. Pro forma basic and diluted income per share will be computed by dividing net income attributable to the Company by the number of shares of common stock outstanding as if the shares of Diamondback issued in the Proposed Contribution Transaction were issued and outstanding for the year ended December 31, 2011.

Recently issued accounting standards

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS, which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between U.S. GAAP and International Financial Reporting Standards. This new guidance changes some fair value measurement principles and disclosure requirements, but does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. The update is effective for annual periods beginning after December 15, 2011. The adoption of this guidance will not have a significant impact on our financial position, results of operations or cash flow.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, Comprehensive Income: Presentation of Comprehensive Income, which provides amendments to FASB ASC Topic 220, Comprehensive Income (FASB ASC 220). The purpose of the amendments in this update is to provide a

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Notes to Consolidated Financial Statements-(Continued)

more consistent method of presenting non-owner transactions that affect an entity s equity. The amendments eliminate the option to report other comprehensive income and its components in the statement of changes in equity and require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. In December 2011, the FASB issued Accounting Standards Update 2011-12 which defers the requirement in Accounting Standards Update 2011-05 that companies present reclassification adjustments for each component of accumulated other comprehensive income in both net income and other comprehensive income on the face of the financial statements. Both amendments are effective for interim and annual periods beginning after December 15, 2011 and should be applied retrospectively. The adoption of this guidance will not have a significant impact on our financial position, results of operations or cash flow.

3. Property and Equipment

Property and equipment includes the following:

	December 31, 2011	December 31, 2010
Oil and natural gas properties:		
Subject to depletion	$ 323,777,751	$ 238,945,878
Not subject to depletion-acquisition costs		
Incurred in 2011	1,199,679	
Incurred in 2010		293,092
Incurred in 2009	532,650	532,650
Total not subject to depletion	1,732,329	825,742
Gross oil and natural gas properties	325,510,080	239,771,620
Less accumulated depreciation, depletion, amortization and impairment	(119,167,476)	(103,989,110)
Oil and natural gas properties, net	206,342,604	135,782,510
Drilling rigs		7,622,586
Workover rigs and related equipment		3,304,577
Other property and equipment	1,016,574	988,617
Less accumulated depreciation	(332,559)	(856,560)
Other property and equipment, net	684,015	11,059,220
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 207,026,619	$ 146,841,730

4. 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.

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Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

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.

A reconciliation of the asset retirement obligation is as follows:

	Year Ended December 31,		
	2011	**2010**	**2009**
Asset retirement obligation, beginning of period	$ 727,826	$ 481,887	$ 374,287
Additional liability incurred	288,640	208,083	79,666
Accretion expense	63,259	37,856	27,934
Asset retirement obligation, end of period	1,079,725	727,826	481,887
Less current portion			
Asset retirement obligations - long-term	$ 1,079,725	$ 727,826	$ 481,887

5. Equity Method Investments

Bison Drilling and Field Services LLC

The Company held a wholly owned subsidiary, Bison Drilling and Field Services LLC (Bison), formerly known as Windsor Drilling LLC, formed on November 15, 2010. In addition, the Company also held a wholly owned subsidiary, West Texas Field Services LLC, formed on March 2, 2010 which, on January 1, 2011, contributed all of its assets and liabilities to Bison. Bison owns and operates four drilling rigs and various oil and 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 consolidated balance sheet and reflected as an equity method investment. The Company now reflects its investment in Bison on the equity method basis of accounting. The Company eliminates any intercompany profits or losses in relation to its continuing involvement with Bison, proportionate to its equity interest.

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

Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

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.

The Company has a 27.2% ownership in Bison at December 31, 2011. As of December 31, 2011, the Company s investment in Bison is reflected as a non-current asset of $6,172,480.

The table below summarizes financial information for Bison as of December 31, 2011:

	December 31, 2011
Current assets	$ 4,438,458
Property and equipment, net	21,707,528
Other assets	880,213
Current liabilities	2,418,902
Equity	24,607,297

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, it is expected that the Company s interest in Muskie will decrease through 2012 to approximately 13%. Muskie generated a loss in 2011 and the Company has recorded its share of this loss. As of December 31, 2011, the Company s investment in Muskie is reflected as a non-current asset of $4,137,188.

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

	December 31, 2011
Current assets	$ 994,166
Property and equipment, net	7,584,779
Current liabilities	26,816
Equity	8,552,129

Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

6. Revolving Bank Credit Facility

Credit Facility-BNP Paribus

On October 15, 2010, the Company executed a secured loan agreement with BNP Paribas (BNP) as the administrative agent, sole book runner and lead arranger. The loan agreement originally provided for a maximum principal amount of $100 million and was increased to $250 million through an amendment dated December 30, 2011. The loan agreement is subject to a collateral borrowing base calculation which is based on the Company s oil and natural gas reserves (the borrowing base). The loan bears 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 3.00% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base.

Principal is payable voluntarily by the Company or is required to be paid (i) if the loan amount exceeds the borrowing base; (ii) if the lender elects to require periodic payments as a part of a borrowing base re-determination; and (iii) at the maturity date of October 14, 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 between scheduled redeterminations. The borrowing base was $45 million at December 31, 2010. The borrowing base increased throughout 2011 through various redeterminations and at December 31, 2011 the borrowing base was $100 million. The current lenders and their percentage commitments in the reserve-based credit facility are BNP (45%), Amegy Bank of Texas (25%), US Bancorp (25%) and West Texas National Bank (5%).

As of December 31, 2011 and 2010, the Company had outstanding borrowings of $85,000,000 and $44,766,687, respectively. The credit facility bears a weighted average interest rate of 3.3% and 3.5% as of December 31, 2011 and 2010, respectively.

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.

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 3.5 to 1.0
Current ratio, as defined in the credit agreement	Not less than 1.0 to 1.0

As of December 31, 2011 and 2010, the Company was in compliance with all financial covenants under the revolving bank credit facility. The lenders may accelerate all of the indebtedness under the revolving bank 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 bank 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.

Credit Facility-Bank of Oklahoma, N.A.

On September 17, 2009, the Company entered into a revolving credit facility with the Bank of Oklahoma, N.A. (BOK). This revolving credit facility was repaid and closed in October 2010 with borrowings from the BNP revolving credit facility. The BOK revolving credit facility had a maximum principal amount of $50 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.

Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

7. Derivatives

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.

All derivative financial instruments are recorded on the consolidated balance sheets 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.

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, 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, 2011.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	December 31, 2011 Fair Value Liability
Crude Oil Swaps:			
January November 2012	335,000	$ 78.50	$ 6,833,265
December 2012	31,000	$ 78.50	594,223
January December 2013	365,000	$ 80.55	5,544,350

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.

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Notes to Consolidated Financial Statements-(Continued)

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, 2011 and 2010, respectively.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	December 31, 2011 Fair Value Liability	December 31, 2010 Fair Value Liability
Crude Oil Swaps:					
December 2010	22,000	$ 82.80	$ 99.45 103.20	$	$ 392,462
January November 2011	180,000	82.90	98.50 102.20		4,159,695
December 2011	90,000	82.90	98.50 102.20	378,750	377,314
January December 2012	270,000	85.07	98.25 101.80	3,876,959	3,844,101

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, 2011 and 2010, respectively.

Description and Production Period	Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	December 31, 2011 Fair Value Asset	December 31, 2010 Fair Value Asset
Crude Oil Swaps:					
December 2010	8,000	82.80	75.00	$	$ 62,400
January November 2011	82,500	82.90	78.42		369,205
December 2011	7,500	82.90	78.42	33,600	33,503
January December 2012	90,000	85.07	80.52	409,380	406,489

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 contracts included in the consolidated statements of operations:

	Years Ended December 31, 2011	2010	2009
Unrealized loss on open non-hedge derivative instruments	$ 12,971,838	$	$
Unrealized loss on locked-in non-hedge derivative instruments			1,297,979
Loss on settlement of non-hedge derivative instruments	37,555	147,983	2,770,026
Loss on derivative contracts	$ 13,009,393	$ 147,983	$ 4,068,005

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 $2,325,643 and $6,528,111 as of December 31, 2011 and 2010, 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.

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Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

8. Equity-Based Compensation

During the year ended December 31, 2011, the Company granted to its executive officers options to acquire membership interests in the Company. Such options vest in four equal annual installments commencing on the first anniversary of the date of grant and are exercisable for five years from the date of grant. Generally, in the event more than 50% of the combined voting power of the Company is not owned by Wexford or its affiliates and there is a material change in the terms of the option holder s employment, the options will vest immediately. 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	$ 1,452,851
August 2011	1.20%	6,000,000	1,383,976
September 2011	1.25%	5,900,000	1,532,612
November 2011	0.25%	1,250,000	288,328
	3.70%	$ 16,750,000	$ 4,657,767

At December 31, 2011, for outstanding options, the intrinsic value was $112,500 and the weighted-average remaining contractual terms were 4.6 years. Also, at December 31, 2011, no options were exercisable.

The Company accounts for such options issued using a fair-value-based method calculated on the grant-date of the award. The resulting cost is 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 is 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 the Company s expectations regarding dividends.

The Company does not have a history of market prices for its membership interests because such interests are 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. The Company does 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:

	Year Ended December 31, 2011
Expected term	5 years
Risk-free interest rate	0.96%
Expected volatility	45.50%
Expected dividend yield	0.00%

As of December 31, 2011, the Company assumed no annual forfeiture rate because of its lack of turnover and lack of history for this type of award. The Company will continue to evaluate the appropriateness of the forfeiture rate based on actual forfeiture experience, analysis of employee turnover behavior, and other factors.

Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

Changes in the estimated forfeiture rate can have a significant effect on reported equity-based compensation expense, because the cumulative effect of adjusting the rate for all expense amortization is recognized in the period the forfeiture estimate is changed.

Equity-based compensation expense recorded for the year ended December 31, 2011 was $544,290. The unrecognized equity-based compensation expense as of December 31, 2011 was $4,113,477 related to these awards which is expected to be recognized over a weighted-average period of 3.6 years. No equity-based compensation expense was recorded for the years ended December 31, 2010 and 2009 as the Company had not historically issued equity-based compensation awards.

9. 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.

The three levels of the fair value hierarchy defined by ASC Topic 820 are as follows:

Level 1 Pricing inputs include quoted prices available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, marketable securities and listed equities.

Level 2 Pricing inputs include quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, investments and interest rate swaps. The Company s valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company utilizes its counterparties valuations to assess the reasonableness of its prices and valuation techniques.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value.

Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

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, 2011 and 2010.

	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, 2011		
Derivative contracts	$	$ 16,784,567	$	$ (2,325,643)	$ 14,458,924
			December 31, 2010		
Derivative contracts	$	$ 7,901,975	$	$ (6,528,111)	$ 1,373,864

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

Level 2 Fair Value Measurements

Derivative contracts-The fair values of the Company s crude oil swaps are measured internally using established index prices and other sources. These are based upon, among other things, futures prices and time to maturity.

Asset Retirement and Environmental Obligations

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, *Asset Retirement and Environmental Obligations* (FASB ASC 410). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 4 for further discussion of the Company s asset retirement obligations. Asset retirement obligations incurred were $288,640, $208,083 and $79,666 during the years ended December 31, 2011, 2010 and 2009, respectively.

10. 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 January 1, 2008. The reimbursement amount for indirect expenses is determined by the affiliate s management based on estimates of office space provided and time devoted to the Company. During the years ended December 31, 2011, 2010 and 2009, the Company incurred total costs of $10,020,059, $7,982,816 and $5,464,190, 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 $1,896,829, $1,375,267 and $831,519 for the years ended December 31, 2011, 2010 and 2009, respectively. Amounts received until February 26, 2010 were through the related party operator discussed below from the Company s working interest partners. As of December 31, 2011 and December 31, 2010, the Company owed the administrative services affiliate $769,278 and $372,121, respectively and such amounts are included in accounts payable-related party in the accompanying consolidated balance sheets.

Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

Operating Services

An entity under common management operated a significant portion of the oil and natural gas properties in which the Company has working and revenue interests. As operator of these properties, this entity was responsible for the daily operations, monthly operation billings and monthly revenue disbursements for the properties in which the Company holds an interest. Effective February 26, 2010, the agreement with this entity was terminated and the Company took over as operator of the properties. As of December 31, 2011, the Company did not have a balance payable to this entity. As of December 31, 2010, the Company had an accounts payable-related party balance to this entity of $73,322.

As of December 31, 2011, amounts due to affiliated parties related to property operations consist of drilling and servicing costs of $153,827, prepaid drilling costs of $209,906 and revenues payable of $2,303,184. As of December 31, 2010 amounts due to affiliated parties consist of prepaid drilling costs of $943,390, tubular goods of $68,875 and revenues payable of $266,414. These amounts are included in accounts payable-related party in the accompanying consolidated balance sheets. Each of these affiliated parties is either controlled by or was an affiliate of Wexford.

As of December 31, 2011 and 2010, amounts due from affiliates related to joint interest billings and included in accounts receivable-related party in the accompanying consolidated balance sheets is $8,990,273 and $5,611,550, respectively. Each of these affiliated parties is either controlled by or was an affiliate of Wexford.

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 $12,511,084, $7,709,051 and $3,261,932 during the years ended December 31, 2011, 2010 and 2009, respectively. Such amounts are capitalized in oil and natural gas properties in the accompanying consolidated balance sheet. At December 31, 2010, approximately $3,061,688 in charges were owed under monthly operations billings and included in accounts payable-related party in the accompanying consolidated balance sheets. At 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 purchases and receives a significant portion of the Company s oil volumes. The Company s revenues from the affiliate were $38,178,686, $21,402,799 and $8,815,681 during the years ended December 31, 2011, 2010 and 2009, respectively, and such amounts are included in oil sales in the accompanying consolidated statements of operations. As of December 31, 2011 and 2010, the Company had an accounts receivable-related party balance with the affiliate of $4,132,316 and $2,730,483, respectively, and such amounts are included in the accompanying consolidated balance sheets.

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. Through December 31, 2011, the Company paid $40,080 under this lease. The current monthly rent under the lease will increase approximately 4% annually on June 1 of each year during the lease term.

Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

Reliance on Wexford

As discussed in Note 1, the Company is wholly owned by an investment fund which is controlled and managed by Wexford. Management believes the credit facility combined with the cash flow generated from operations will be sufficient to sustain the Company s operations through the end of 2012; however, if additional financing is required management will seek additional sources with could include Wexford.

11. 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.

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 with a lease term of five years. (See Note 10) Future minimum lease payments for these leases are as follows as of December 31, 2011:

2012	$ 219,074
2013	222,379
2014	229,566
2015	237,929
2016	185,358
Thereafter	172,600
Total	$ 1,266,906

Rent expense for the year ended December 31, 2011 was $74,279.

12. Subsequent Events

The Company has evaluated the period after December 31, 2011 through March 23, 2012, the date the financial statements were available to be issued, noting no subsequent events or transactions that required recognition or disclosure in the financial statements, other than noted below.

On February 21, 2012, Wells Fargo & Company announced it had agreed to purchase BNP Paribas energy lending business in the United States and that the purchase is subject to regulatory and other approvals and is expected to close in the second quarter of 2012. BNP Paribas is administrative agent, sole book runner and lead arranger of our reserve-based credit facility with 45% of our current borrowing base of $100 million, and a counterparty to certain of our commodity derivatives. The purchase of BNP s energy lending business by Wells Fargo & Company should not have an effect on the Company s credit facility.

13. Supplemental Information on Oil and Natural Gas Operations (Unaudited)

The following supplemental unaudited information regarding the oil and natural gas activities of the Company is presented pursuant to the disclosure requirements promulgated by the United States Securities and Exchange Commission (the SEC) and the FASB ASU 2010-03, Extractive Activities-Oil and Gas (Topic 932) . The

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Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

reserve reports were prepared in accordance with guidelines established by the SEC and, accordingly, were based on existing economic and operating conditions.

Proved oil and natural gas reserve estimates as of December 31, 2010 and 2009 were prepared by Pinnacle Energy Services, LLC and as of December 31, 2011 were prepared by Ryder Scott Company L.P., both independent petroleum engineers.

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

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

	Year Ended December 31, 2011	2010	2009
Acquisition costs:			
Proved properties	$	$	$
Unproved properties	3,213,932	2,393,744	1,816,032
Development costs	72,661,524	47,434,500	16,399,583
Exploration costs	9,574,364	3,394,329	851,036
Capitalized asset retirement costs	288,640	208,083	79,666
Total	$ 85,738,460	$ 53,430,656	$ 19,146,317

Results of Operations from Oil and Natural Gas Producing Activities

The Company s results of operations from oil, natural gas and natural gas liquid producing activities are presented below for years ended December 31, 2011, 2010 and 2009. 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, 2011	2010	2009
Oil, natural gas and natural gas liquid sales	$ 47,180,802	$ 26,441,927	$ 12,716,011
Lease operating expenses	(10,345,355)	(4,588,559)	(2,366,623)
Production taxes	(2,333,853)	(1,346,879)	(663,068)
Gathering and transportation	(201,828)	(105,870)	(42,091)
Depreciation, depletion and amortization	(15,178,366)	(7,373,126)	(3,155,084)
Results of operations from oil, natural gas and natural gas liquids	$ 19,121,400	$ 13,027,493	$ 6,489,145

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Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

Oil and Natural Gas Reserves

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, 2009	1,750,440	771,625	2,945,130
Extensions and discoveries	746,019	128,998	478,092
Revisions of previous estimates	26,903,222	6,691,986	24,311,919
Purchase of reserves in place			
Production	(168,741)	(70,384)	(253,321)
Sales of reserves in place			
As of December 31, 2009	29,230,940	7,522,225	27,481,820
Extensions and discoveries	1,591,094	1,194,217	13,011,377
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	18,819,050	5,563,978	21,662,720
Extensions and discoveries	1,705,680	448,165	1,824,337
Revisions of previous estimates	(3,366,041)	(1,162,054)	(3,454,552)
Purchase of reserves in place			
Production	(441,822)	(86,815)	(413,640)
Sales of reserves in place			
As of December 31, 2011	16,716,867	4,763,274	19,618,865
Proved Developed Reserves:			
January 1, 2009	1,750,440	771,625	2,945,130
December 31, 2009	1,954,060	591,532	2,453,750
December 31, 2010	3,307,550	1,105,216	4,255,300
December 31, 2011	3,805,291	1,233,319	5,186,941
Proved Undeveloped Reserves:			
January 1, 2009			
December 31, 2009	27,276,880	6,930,693	25,028,070

December 31, 2010	15,511,500	4,458,762	17,407,420
December 31, 2011	12,911,576	3,529,955	14,431,924

As of December 31, 2011, 2010 and 2009 reserves were computed using the 12-month unweighted average of the first-day-of-the-month prices, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2009.

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.

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Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

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.

The Company experienced upward reserve revisions in 2009, due to the pricing recovery in 2009 and the amendments of ASC 932 in ASU 2010-03.

The increase in 2009 reserves described above had an effect on our depletion and net loss in 2009. The Company is unable to estimate the effect on the 2009 financial statements of the SEC Modernization of the Oil and Gas Reporting Requirement rule that was effective as of December 31, 2009 because a comparative reserve report prepared under the previous rules does not exist.

As of December 31, 2008 all proved undeveloped reserves were noneconomic due to the commodity pricing utilized for the reserve estimate at year end.

Standardized Measure of Discounted Future Net Cash Flows

The following information has been prepared in accordance with the provisions of the FASB ASU 2010-03, Extractive Activities Oil and Gas (Topic 932). As of December 31, 2011, 2010 and 2009 the standardized measure of discounted future net cash flows are based on the 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 Company s investment and operating decisions are not based on the information presented, but on a wide range of reserve estimates that include probable as well as proved reserves and on different price and cost assumptions.

The standardized measure is intended to provide a better means for comparing the value of the Company s proved reserves at a given time with those of other oil and gas producing companies than is provided by a comparison of raw proved reserve quantities.

	December 31,		
	2011	**2010**	**2009**
Future cash inflows	$ 1,901,127,669	$ 1,776,887,010	$ 2,040,811,600
Future development costs	(373,750,257)	(376,204,640)	(397,076,030)
Future production costs	(458,939,218)	(365,712,860)	(429,507,800)
Future production taxes	(97,457,261)	(121,987,210)	(138,799,710)
Future net cash flows	970,980,933	912,982,300	1,075,428,060
10% discount to reflect timing of cash flows	(627,533,692)	(582,624,480)	(682,509,150)
Standardized measure of discounted future net cash flows	$ 343,447,241	$ 330,357,820	$ 392,918,910

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Windsor Permian LLC and Subsidiaries

Notes to Consolidated Financial Statements-(Continued)

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.

	December 31, 2011	2010	2009
	Unweighted Arithmetic Average First-Day-of-the- Month Prices		
Oil (per Bbl)	$ 93.09	$ 77.61	$ 58.84
Natural gas (per Mcf)	$ 3.91	$ 4.14	$ 3.64
Natural gas liquids (per Bbl)	$ 56.33	$ 40.74	$ 29.37

The effect of the adoption of the revised SEC rules as of December 31, 2009 with respect to the use of the 12-month unweighted average price caused decreases in reserve volumes and pricing as follows:

oil volumes of 515,390 Bbls and $18.18 per Bbl;

natural gas liquids volumes of 130,100 Bbls and $8.85 per Bbl; and

gas volumes of 537,010 Mcf and $1.84 per Mcf.

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, 2011	2010	2009
Standardized measure of discounted future net cash flows at the beginning of the period	$ 330,357,820	$ 392,918,910	$ 41,435,980
Sales of oil and natural gas, net of production costs	(34,299,766)	(20,400,619)	(9,644,229)
Purchase of minerals in place			
Extensions and discoveries, net of future development costs	69,375,680	52,678,768	18,489,620
Development costs incurred during the period	83,166,092	51,023,970	16,345,261
Net changes in prices and production costs	80,480,005	178,197,726	7,580,209
Changes in estimated future development costs	(76,990,690)	(23,991,650)	(409,015,151)
Revisions of previous quantity estimates	(100,433,225)	(292,306,238)	798,975,216
Sales of reserves in place, net of future development costs			
Accretion of discount	33,035,782	39,291,891	4,143,598
Net changes in timing of production and other	(41,244,457)	(47,054,938)	(75,391,594)
Standardized measure of discounted future net cash flows at the end of the period	$ 343,447,241	$ 330,357,820	$ 392,918,910

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Report of Independent Certified Public Accountants

Members

Windsor UT LLC

We have audited the accompanying balance sheets of Windsor UT LLC (a Delaware limited liability company) as of December 31, 2011 and 2010, and the related statement of operations, changes in members equity and cash flows for the year ended December 31, 2011 and the period from inception (April 28, 2010) to December 31, 2010. 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 auditing standards generally accepted in the United States of America established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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 financial statements referred to above present fairly, in all material respects, the financial position of Windsor UT LLC as of December 31, 2011 and 2010, and the results of its operations and its cash flows for the year ended December 31, 2011 and the period from inception (April 28, 2010) to December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

/s/ Grant Thornton LLP

Oklahoma City, Oklahoma

May 1, 2012

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Windsor UT LLC

Balance Sheets

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 156,733	$ 29,536
Accounts receivable-related party	214,633	
Total current assets	371,366	29,536
Property and equipment		
Oil and natural gas properties, at cost, based on the full cost method of accounting ($2,796,065 and $7,144,265 excluded from amortization at December 31,2011 and 2010, respectively)	14,321,344	9,458,667
Accumulated depletion, depreciation and amortization	(198,712)	
	14,122,632	9,458,667
Prepaid drilling costs-related party		251,715
Total assets	$ 14,493,998	$ 9,739,918
Liabilities and Members Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 395	$ 1,100
Accounts payable related party	279,988	15,849
Total current liabilities	280,383	16,949
Asset retirement obligations	24,267	14,436
Total liabilities	304,650	31,385
Commitments and contingencies (Note 6)		
Members equity	14,189,348	9,708,533
Total liabilities and members equity	$ 14,493,998	$ 9,739,918

See accompanying notes to financial statements.

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Windsor UT LLC

Statements of Operations

	Year Ended December 31, 2011	Period from Inception (April 28, 2010) to December 31, 2010
Revenues:		
Oil sales-related party	$ 694,666	$
Total revenues	694,666	
Costs and expenses:		
Lease operating expenses	251,824	
Production taxes	32,016	
Depreciation, depletion and amortization	198,712	
General and administrative expenses	37,044	
Asset retirement obligation accretion expense	1,255	
Total costs and expenses	520,851	
Net income	$ 173,815	$

See accompanying notes to financial statements.

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Windsor UT LLC

Statement of Changes in Members Equity

	Total members equity
Balance at inception (April 28, 2010)	$
Contributions	9,708,533
Balance at December 31, 2010	9,708,533
Contributions	4,307,000
Net income	173,815
Balance at December 31, 2011	$ 14,189,348

See accompanying notes to financial statements.

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Windsor UT LLC

Statements of Cash Flows

	Year Ended December 31, 2011	Period from Inception (April 28, 2010) to December 31, 2010
Cash flows from operating activities:		
Net income	$ 173,815	$
Adjustments to reconcile net income to net cash provided by operating activities:		
Asset retirement obligation accretion expense	1,255	
Depreciation, depletion, and amortization	198,712	
Changes in operating assets and liabilities:		
Accounts receivable-related party	(214,633)	
Accounts payable and accrued liabilities	(705)	1,100
Accounts payable and accrued liabilities-related party	55,102	15,849
Net cash provided by operating activities	213,546	16,949
Cash flows from investing activities:		
Additions to oil and natural gas properties-related party	(4,393,349)	(2,102,413)
Net cash used in investing activities	(4,393,349)	(2,102,413)
Cash flows from financing activities:		
Contributions by members	4,307,000	2,115,000
Net cash provided by financing activities	4,307,000	2,115,000
Net increase in cash and cash equivalents	127,197	29,536
Cash and cash equivalents at beginning of period	29,536	
Cash and cash equivalents at end of period	$ 156,733	$ 29,536
Supplemental cash flow information		
Asset retirement obligation incurred, including changes in estimate	$ 8,576	$ 14,436
Property contributed	$	$ 7,593,533

See accompanying notes to financial statements.

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Windsor UT LLC

Notes to Financial Statements

1. Organization

Windsor UT LLC (the Company) is a limited liability company formed on April 28, 2010 to acquire, produce, develop and exploit oil and natural gas properties. As a limited liability company, the members of the Company are not liable for the liabilities or other obligations of the Company. The Company is wholly owned by investment funds which are controlled and managed by Wexford Capital LP (Wexford).

The Company is engaged in the acquisition, exploitation, development and production of oil and natural gas properties and related sale of oil, natural gas and natural gas liquids. The Company s reserves are located in the Southern region of the United States. The Company s results of operations are largely dependent on the difference between the prices received for its oil, natural gas and natural gas liquids and the cost to find, develop, produce and market such resources. Oil and natural gas prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond the Company s control. These factors include worldwide political instability, quantity of natural gas in storage, foreign supply of oil and natural gas, the price of foreign imports, the level of consumer demand and the price of available alternative fuels, among others. The Company was a development stage enterprise at December 31, 2010.

2. Summary of Significant Accounting Policies

The Company s financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America.

Use of estimates

Certain amounts included in or affecting the Company s 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 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 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 reserve quantities and related estimates of the present value of future net revenues, the carrying value of oil and gas properties and asset retirement obligations.

Cash and Cash Equivalents

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

Accounts Receivable

Accounts receivable consist primarily of receivables for oil and natural gas production delivered to purchasers. Those purchasers remit payment for production to the operator of the respective producing properties and the operator, in turn, remits payment to the Company. As discussed in Note 5, the Company s oil and natural gas properties are contractually operated by an affiliate. Most payments are received within three months after the production date.

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Windsor UT LLC

Notes to Financial Statements-(Continued)

Accounts receivable are stated at amounts due from purchasers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. 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, 2011 or 2010.

Fair Value of Financial Instruments

The Company s financial instruments consist of cash and cash equivalents, receivables and payables. The carrying amount of cash and cash equivalents, receivables and payables approximates fair value because of the short-term nature of the instruments.

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. 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. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The average depletion rate per barrel equivalent unit of production was $26.11 for the year ended December 31, 2011 and because the Company did not have any production in 2010 there was no depletion for the period ended December 31, 2010. Depreciation, depletion and amortization expense for oil and natural gas properties was $198,712 for the year ended December 31, 2011, and there was no expense for the period ended December 31, 2010.

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. No impairment on proved oil and natural gas properties was recorded for the periods ended December 31, 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. The inclusion of the Company s unevaluated costs into the amortization base is expected to be completed within three years.

Windsor UT LLC

Notes to Financial Statements-(Continued)

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, 2011 and 2010.

Concentrations

During the year period ended December 31, 2011, the Company sold its production to one purchaser. Windsor Midstream LLC, an entity controlled by Wexford, accounted for 100% of the oil revenue. The Company believes there are other crude oil purchasers to whom it would be able to sell its oil if the current purchaser discontinued purchasing from the Company.

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

The operations of the Company, as a limited liability company, is not subject to federal income taxes. As appropriate, the taxable income or loss applicable to operations is included in the federal income tax returns of the respective owners and no income tax effect is included in the accompanying financial statements. The Company is subject to margin tax in the state of Texas. During the periods ended December 31, 2011 and 2010, there was no margin tax expense. The Company s 2010 federal income tax and state margin tax returns remain open to examination by tax authorities. As of December 31, 2011 and 2010, the Company has 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 periods ended December 31, 2011 and 2010 there was no interest or penalties associated with uncertain tax positions in the Company s financial statements.

Recently issued accounting standards

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS, which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between U.S. GAAP and International Financial Reporting Standards. This new guidance changes some fair value measurement principles and disclosure requirements, but does not require additional fair value measurements and is not intended to establish valuation standards or affect valuation practices outside of financial reporting. The update is effective for annual periods beginning after December 15, 2011. The adoption of this guidance will not have a significant impact on the Company s financial position, results of operations or cash flow.

Windsor UT LLC

Notes to Financial Statements-(Continued)

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, Comprehensive Income: Presentation of Comprehensive Income, which provides amendments to FASB ASC Topic 220, Comprehensive Income (FASB ASC 220). The purpose of the amendments in this update is to provide a more consistent method of presenting non-owner transactions that affect an entity s equity. The amendments eliminate the option to report other comprehensive income and its components in the statement of changes in equity and require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. In December 2011, the FASB issued Accounting Standards Update 2011-12 which defers the requirement in Accounting Standards Update 2011-05 that companies present reclassification adjustments for each component of accumulated other comprehensive income in both net income and other comprehensive income on the face of the financial statements. Both amendments are effective for interim and annual periods beginning after December 15, 2011 and should be applied retrospectively. The adoption of this guidance will not have a significant impact on the Company s financial position, results of operations or cash flow.

3. Property and Equipment

Property and equipment includes the following:

	December 31, 2011	December 31, 2010
Oil and natural gas properties:		
Subject to depletion	$ 11,525,279	$ 2,314,402
Not subject to depletion-acquisition costs		
Incurred in 2011	490,007	
Incurred in 2010	2,306,058	7,144,265
Total not subject to depletion	2,796,065	7,144,265
Gross oil and natural gas properties	14,321,344	9,458,667
Less accumulated depreciation, depletion and amortization	(198,712)	
Oil and natural gas properties, net	$ 14,122,632	$ 9,458,667

4. 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.

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Windsor UT LLC

Notes to Financial Statements-(Continued)

A reconciliation of the asset retirement obligation is as follows:

	Year Ended December 31, 2011	Period from Inception (April 28, 2010) to December 31, 2010
Asset retirement obligation, beginning of period	$ 14,436	$
Additional liability incurred	8,576	14,436
Accretion expense	1,255	
Asset retirement obligation, end of period	24,267	14,436
Less current portion		
Asset retirement obligation, long-term	$ 24,267	$ 14,436

5. 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 April 28, 2010. The reimbursement amount for indirect expenses is determined by the affiliate s management based on estimates of office space provided and time devoted to the Company. During the periods ended December 31, 2011 and 2010, the Company incurred total costs of $90,127 and $12,879, respectively. Costs incurred unrelated to drilling activities are expensed and costs incurred in the acquisition, exploration, and development of oil and natural gas properties have been capitalized. The expensed costs were partially offset in general and administrative expenses by overhead reimbursements of $57,250 and $14,437 for the periods ended December 31, 2011 and 2010, respectively which were received through the related party operator discussed below. As of December 31, 2011 and December 31, 2010, the Company owed the administrative services affiliate $3,864 and $709, respectively and such amounts are included in accounts payable-related party in the accompanying balance sheets.

Operating Services

An entity under common management operates the oil and natural gas properties in which the Company has working and revenue interests. As operator of these properties, this entity is responsible for the daily operations, monthly operation billings and monthly revenue disbursements for the properties. As of December 31, 2011 and 2010 the Company has an accounts payable balance to this entity of $276,124 and $15,140, respectively.

As of December 31, 2010, $251,715 was prepaid to the operator for prepaid drilling costs and as of December 31, 2011 there were no amounts prepaid for drilling costs to the operator. This amount is included in prepaid drilling costs-related party in the accompanying balance sheets.

Marketing Services

An entity under common management purchases and receives all of the Company s oil volumes. The Company s revenues from the affiliate during year ended December 31, 2011 were $694,666. As of December 31, 2011 the Company had an accounts receivable balance with the affiliate of $214,633.

Reliance on Wexford

As discussed in Note 1, the Company is wholly owned by investment funds which are controlled and managed by Wexford. Management believes cash flows generated from operations will be sufficient to sustain the Company s

Windsor UT LLC

Notes to Financial Statements-(Continued)

operations through the end of 2012; however, if additional financing is required to continue to develop our properties management will seek additional sources which could include Wexford.

6. 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.

7. Subsequent Events

The Company has evaluated the period after December 31, 2011 through May 1, 2012 the date the financial statements were available to be issued, noting no subsequent events or transactions that required recognition or disclosure in the financial statements, other than noted below.

Wexford has agreed in principle to cause all the outstanding equity interests in the Company to be contributed to Windsor Permian LLC, an entity under common control. This contribution will close prior to the initial public offering of Diamondback Energy Inc. who will be the parent of Windsor Permian LLC.

8. Supplemental Information on Oil and Natural Gas Operations (Unaudited)

The following supplemental unaudited information regarding the oil and natural gas activities of the Company is presented pursuant to the disclosure requirements promulgated by the United States Securities and Exchange Commission (the SEC) and the FASB ASU 2010-03, Extractive Activities-Oil and Gas (Topic 932) . The reserve reports were prepared in accordance with guidelines established by the SEC and, accordingly, were based on existing economic and operating conditions.

Proved oil and natural gas reserve estimates as of December 31, 2010 were prepared by Pinnacle Energy Services, LLC and as of December 31, 2011 were prepared by Ryder Scott Company L.P., both independent petroleum engineers.

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

Windsor UT LLC

Notes to Financial Statements-(Continued)

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

	Year Ended December 31, 2011	2010
Acquisition costs:		
Proved properties	$	$
Unproved properties	490,029	7,536,554
Development costs	2,712,638	1,381,594
Exploration costs	1,651,434	526,083
Capitalized asset retirement costs	8,576	14,436
Total	$ 4,862,677	$ 9,458,667

Results of Operations from Oil and Natural Gas Producing Activities

The Company s results of operations from oil and natural gas producing activities are presented below for year ended December 31, 2011. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to net operating results of our oil, natural gas and natural gas liquids operations.

	Year Ended December 31, 2011
Oil sales	$ 694,666
Lease operating expenses	(251,824)
Production taxes	(32,016)
Depreciation, depletion and amortization	(198,712)
Results of operations from oil, natural gas and natural gas liquids	$ 212,114

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Windsor UT LLC

Notes to Financial Statements-(Continued)

Oil and Natural Gas Reserves

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 Inception (April 28, 2010)			
Extensions and discoveries	811,110	268,989	1,032,360
Revisions of previous estimates			
Purchase of reserves in place			
Production			
Sales of reserves in place			
As of December 31, 2010	811,110	268,989	1,032,360
Extensions and discoveries	93,495	18,374	59,855
Revisions of previous estimates	486,613	(1,076)	(159,615)
Purchase of reserves in place			
Production	(7,611)		
Sales of reserves in place			
As of December 31, 2011	1,383,607	286,287	932,600
Proved Developed Reserves:			
December 31, 2010	63,910	21,215	81,420
December 31, 2011	143,808	30,392	99,004
Proved Undeveloped Reserves:			
December 31, 2010	747,200	247,774	950,940
December 31, 2011	1,239,799	255,895	833,596

As of December 31, 2011 and 2010 reserves were computed using the trailing 12-month unweighted average of the first-day-of-the-month prices, in accordance with the SEC guidelines applicable to reserves estimates.

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.

Standardized Measure of Discounted Future Net Cash Flows

The following information has been prepared in accordance with the provisions of the FASB ASU 2010-03, Extractive Activities Oil and Gas (Topic 932). As of December 31, 2011 and 2010 the standardized measure of discounted future net cash flows are based on the trailing 12-month unweighted average, first-day-of-the-month prices.

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.

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Windsor UT LLC

Notes to Financial Statements-(Continued)

The Company s investment and operating decisions are not based on the information presented, but on a wide range of reserve estimates that include probable as well as proved reserves and on different price and cost assumptions.

The standardized measure is intended to provide a better means for comparing the value of the Company s proved reserves at a given time with those of other oil and gas producing companies than is provided by a comparison of raw proved reserve quantities.

	December 31,	
	2011	2010
Future cash inflows	$ 148,561,297	$ 79,406,680
Future development costs	(36,600,000)	(22,100,000)
Future production costs	(38,872,203)	(19,203,120)
Future production taxes	(7,410,909)	(4,102,820)
Future net cash flows	65,678,185	34,000,740
10% discount to reflect timing of cash flows	(47,669,824)	(25,357,600)
Standardized measure of discounted future net cash flows	$ 18,008,361	$ 8,643,140

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

	December 31,	
	2011	2010
Oil (per Bbl)	$ 92.99	$ 78.76
Natural gas (per Mcf)	$ 3.92	$ 4.26
Natural gas liquids (per Bbl)	$ 56.74	$ 41.34

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,	
	2011	2010
Standardized measure of discounted future net cash flows at the beginning of the period	$ 8,643,140	$
Sales of oil and natural gas, net of production costs	(410,826)	
Net changes in prices and production costs	1,883,765	
Purchase of minerals in place		
Development costs incurred during the period	4,364,072	1,907,677
Extensions and discoveries, net of future development costs	4,195,434	6,735,463
Change in estimated future development costs	(5,864,072)	
Revisions of previous quantity estimates	1,899,993	
Sales of reserves in place		
Accretion of discount	864,314	
Net changes in timing of production and other	2,432,541	
Standardized measure of discounted future net cash flows at the end of the period	$ 18,008,361	$ 8,643,140

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Report of Independent Certified Public Accountants
Board of Directors

Gulfport Energy Corporation

We have audited the accompanying statements of revenues and direct operating expenses of working and revenue interests of certain oil and gas properties (the Properties) owned by Gulfport Energy Corporation (Gulfport) for the years ended December 31, 2011 and 2010. These statements are the responsibility of Gulfport s management. Our responsibility is to express an opinion on these statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the statements are free of material misstatement. An audit includes 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 Properties 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 presentation of the statements. We believe that our audits provide a reasonable basis for our opinion.

As described in Note A, the accompanying statements are prepared for the purpose of complying with the rules and regulations of the Securities and Exchange Commission and is not intended to be a complete financial presentation.

In our opinion, the statements referred to above present fairly, in all material respects, the revenues and direct operating expenses as described in Note A for the years ended December 31, 2011 and 2010.

/s/ Grant Thornton LLP

Oklahoma City, Oklahoma

April 24, 2012

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CERTAIN PROPERTY INTERESTS OF

GULFPORT ENERGY CORPORATION

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

	Year Ended December 31, 2011	2010
Revenues:		
Oil and gas sales	$ 23,052,000	$ 14,088,000
Direct operating expenses		
Lease operating expenses	5,484,000	2,375,000
Production taxes	1,276,000	806,000
Total direct operating expenses	6,760,000	3,181,000
Revenues in excess of direct operating expenses	$ 16,292,000	$ 10,907,000

See accompanying notes to statements of revenues and direct operating expenses.

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CERTAIN PROPERTY INTERESTS OF

GULFPORT ENERGY CORPORATION

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

FOR THE YEARS ENDED DECEMBER 31, 2011 AND 2010

NOTE A BASIS OF PRESENTATION

The accompanying statements present the revenues and direct operating expenses of working and revenue interests of certain oil and natural gas properties located in the Permian Basin of West Texas (the Properties) owned by Gulfport Energy Corporation (Gulfport) for the years ended December 31, 2011 and 2010.

The accompanying statements of revenues and direct operating expenses are presented on the accrual basis of accounting and were derived from the historical accounting records of Gulfport. Such amounts may not be representative of future operations. The statements do not include depreciation, depletion and amortization, general and administrative expenses, income taxes or interest expense as these costs may not be comparable to the expenses expected to be incurred on a prospective basis.

Historical financial statements reflecting financial position, results of operations and cash flows required by accounting principles generally accepted in the United States of America are not presented as such information is not readily available on an individual property basis. Accordingly, the historical statements of revenues and direct operating expenses of the Properties are presented in lieu of the financial statements required under Rule 3-05 of the Securities and Exchange Commission Regulation S-X.

NOTE B SIGNIFICANT ACCOUNTING POLICIES

Use of estimates

The preparation of the accompanying statements in conformity with generally accepted accounting principles requires making estimates and assumptions that affect the reported amounts of revenues and direct operating expenses during the reporting period. The estimates include oil and gas revenue accruals and reserve quantities. It is emphasized that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Actual results could materially differ from these estimates.

Revenue recognition

Oil and natural gas revenues are recorded when title passes to the purchaser, net of royalty interests, discounts and allowances, as applicable.

NOTE C SUPPLEMENTAL OIL AND GAS RESERVE INFORMATION (UNAUDITED)

The proved oil and gas reserves attributable to the Properties consist of the estimated quantities of crude oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The weighted average prices used for reserve report purposes are $96.19 and $4.12 for December 31, 2011 and $79.43 and $4.38 at December 31, 2010, adjusted for transportation fees and regional price differentials, for oil and natural gas reserves, respectively. The following estimates of proved reserves have been made by the independent engineering firms of Ryder Scott Company L.P. and Pinnacle Energy Services, LLC based on the Gulfport s net revenue interest for 2011 and 2010, respectively.

Oil and gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and

CERTAIN PROPERTY INTERESTS OF

GULFPORT ENERGY CORPORATION

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

FOR THE YEARS ENDED DECEMBER 31, 2011 AND 2010-(CONTINUED)

geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. Reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

	2011		2010	
	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)
Proved Reserves				
Beginning of the period	12,465	11,926	9,763	10,894
Purchases in oil and gas reserves in place			3,566	3,341
Extensions and discoveries	981	992	3,701	3,512
Revisions of prior reserve estimates	(2,302)	(599)	(4,365)	(5,565)
Current production	(267)	(272)	(200)	(256)
End of period	10,877	12,047	12,465	11,926
Proved developed reserves	2,803	3,050	2,634	3,048
Proved undeveloped reserves	8,074	8,997	9,831	8,878

Proved developed reserves as of January 1, 2010 were 1,560 MBbls of oil and 2,009 MMcf of gas and proved undeveloped reserves as of January 1, 2010 were 8,203 MBbls of oil and 8,885 MMcf of gas.

Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows is computed by applying unweighted average first-of-the-month prices of oil and natural gas, adjusted for transportation fees and regional price differentials, to the estimated future production of proved oil and gas reserves less estimated future expenditures (based on certain prevailing economic conditions) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Income taxes are excluded because the property interests included represent only a portion of a business for which income taxes are not estimable.

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CERTAIN PROPERTY INTERESTS OF

GULFPORT ENERGY CORPORATION

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

FOR THE YEARS ENDED DECEMBER 31, 2011 AND 2010-(CONTINUED)

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and gas properties. Estimates of fair value would also take into account, among other things, probable and possible reserves, anticipated future oil and natural gas prices, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

	Year ended December 31,	
	2011	**2010**
Future cash flows	$ 960,918,000	$ 902,221,000
Future development and abandonment costs	(236,336,000)	(196,265,000)
Future production costs	(166,899,000)	(208,210,000)
Future production taxes	(50,235,000)	(46,605,000)
Future net cash flows	507,448,000	451,141,000
10% discount to reflect timing of cash flows	(305,160,000)	(289,035,000)
Standardized measure of discounted future net cash flows	$ 202,288,000	$ 162,106,000

Changes in standardized measure of discounted future net cash flows

	Year ended December 31,	
	2011	**2010**
Sales and transfers of oil and gas produced, net of production costs	$ (16,292,000)	$ (10,907,000)
Net changes in prices, production costs and development costs	48,089,000	37,212,000
Acquisition of oil and gas reserves in place		81,901,000
Extensions and discoveries	29,432,000	84,971,000
Revisions of previous quantity estimates, less related production costs	(71,088,000)	(99,257,000)
Accretion of discount	16,211,000	9,143,000
Change in production rates and other	33,830,000	(32,389,000)
Total change in standardized measure of discounted future net cash flows	$ 40,182,000	$ 70,674,000

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Dealer Prospectus Delivery Obligation

Until , 2012 (25 days after commencement of this offering), all dealers that effect transactions in these securities, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealer s obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. Other Expenses of Issuance and Distribution.

The following table sets forth the fees and expenses in connection with the issuance and distribution of the securities being registered hereunder. Except for the SEC registration fee and FINRA filing fee, all amounts are estimates.

SEC registration fee	$ 5,730
FINRA filing fee	*
NASDAQ Global Market listing fee	*
Accounting fees and expenses	*
Legal fees and expenses	*
Blue Sky fees and expenses (including counsel fees)	*
Printing and Engraving expenses	*
Transfer Agent and Registrar fees and expenses	*
Miscellaneous expenses	*
Total	$ *

* To be completed by amendment.

Item 14. Indemnification of Directors and Officers.

Limitation of Liability

Section 102(b)(7) of the Delaware General Corporation Law, or the DGCL, permits a corporation, in its certificate of incorporation, to limit or eliminate, subject to certain statutory limitations, the liability of directors to the corporation or its stockholders for monetary damages for breaches of fiduciary duty, except for liability:

- for any breach of the director s duty of loyalty to the company or its stockholders;
- for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law;
- in respect of certain unlawful dividend payments or stock redemptions or repurchases; and
- for any transaction from which the director derives an improper personal benefit.

In accordance with Section 102(b)(7) of the DGCL, Section 9.1 of our certificate of incorporation provides that that no director shall be personally liable to us or any of our stockholders for monetary damages resulting from breaches of their fiduciary duty as directors, except to the extent such limitation on or exemption from liability is not permitted under the DGCL. The effect of this provision of our certificate of incorporation is to eliminate our rights and those of our stockholders (through stockholders derivative suits on our behalf) to recover monetary damages against a director for breach of the fiduciary duty of care as a director, including breaches resulting from negligent or grossly negligent behavior, except, as restricted by Section 102(b)(7) of the DGCL. However, this provision does not limit or eliminate our rights or the rights of any stockholder to seek non-monetary relief, such as an injunction or rescission, in the event of a breach of a director s duty of care.

If the DGCL is amended to authorize corporate action further eliminating or limiting the liability of directors, then, in accordance with our certificate of incorporation, the liability of our directors to us or our stockholders will be eliminated or limited to the fullest extent authorized by the DGCL, as so amended. Any repeal or amendment of provisions of our certificate of incorporation limiting or eliminating the liability of directors, whether by our stockholders or by changes in law, or the adoption of any other provisions inconsistent therewith, will (unless otherwise required by law) be prospective only, except to the extent such amendment or change in law permits us to further limit or eliminate the liability of directors on a retroactive basis.

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Indemnification

Section 145 of the DGCL permits a corporation, under specified circumstances, to indemnify its directors, officers, employees or agents against expenses (including attorneys fees), judgments, fines and amounts paid in settlements actually and reasonably incurred by them in connection with any action, suit or proceeding brought by third parties by reason of the fact that they were or are directors, officers, employees or agents of the corporation, if such directors, officers, employees or agents acted in good faith and in a manner they reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, had no reason to believe their conduct was unlawful. In a derivative action, i.e., one by or in the right of the corporation, indemnification may be made only for expenses actually and reasonably incurred by directors, officers, employees or agents in connection with the defense or settlement of an action or suit, and only with respect to a matter as to which they shall have acted in good faith and in a manner they reasonably believed to be in or not opposed to the best interests of the corporation, except that no indemnification shall be made if such person shall have been adjudged liable to the corporation, unless and only to the extent that the court in which the action or suit was brought shall determine upon application that the defendant directors, officers, employees or agents are fairly and reasonably entitled to indemnity for such expenses despite such adjudication of liability

Our certificate of incorporation provides that we will, to the fullest extent authorized or permitted by applicable law, indemnify our current and former directors and officers, as well as those persons who, while directors or officers of our corporation, are or were serving as directors, officers, employees or agents of another entity, trust or other enterprise, including service with respect to an employee benefit plan, in connection with any threatened, pending or completed proceeding, whether civil, criminal, administrative or investigative, against all expense, liability and loss (including, without limitation, attorney s fees, judgments, fines, ERISA excise taxes and penalties and amounts paid in settlement) reasonably incurred or suffered by any such person in connection with any such proceeding. Notwithstanding the foregoing, a person eligible for indemnification pursuant to our certificate of incorporation will be indemnified by us in connection with a proceeding initiated by such person only if such proceeding was authorized by our board of directors, except for proceedings to enforce rights to indemnification.

The right to indemnification conferred by our certificate of incorporation is a contract right that includes the right to be paid by us the expenses incurred in defending or otherwise participating in any proceeding referenced above in advance of its final disposition, provided, however, that if the DGCL requires, an advancement of expenses incurred by our officer or director (solely in the capacity as an officer or director of our corporation) will be made only upon delivery to us of an undertaking, by or on behalf of such officer or director, to repay all amounts so advanced if it is ultimately determined that such person is not entitled to be indemnified for such expenses under our certificate of incorporation or otherwise.

The rights to indemnification and advancement of expenses will not be deemed exclusive of any other rights which any person covered by our certificate of incorporation may have or hereafter acquire under law, our certificate of incorporation, our bylaws, an agreement, vote of stockholders or disinterested directors, or otherwise.

Any repeal or amendment of provisions of our certificate of incorporation affecting indemnification rights, whether by our stockholders or by changes in law, or the adoption of any other provisions inconsistent therewith, will (unless otherwise required by law) be prospective only, except to the extent such amendment or change in law permits us to provide broader indemnification rights on a retroactive basis, and will not in any way diminish or adversely affect any right or protection existing at the time of such repeal or amendment or adoption of such inconsistent provision with respect to any act or omission occurring prior to such repeal or amendment or adoption of such inconsistent provision. Our certificate of incorporation also permits us, to the extent and in the manner authorized or permitted by law, to indemnify and to advance expenses to persons other that those specifically covered by our certificate of incorporation.

Our bylaws include the provisions relating to advancement of expenses and indemnification rights consistent with those set forth in our certificate of incorporation. In addition, our bylaws provide for a right of indemnitee to bring a suit in the event a claim for indemnification or advancement of expenses is not paid in full by us within a specified period of time. Our bylaws also permit us to purchase and maintain insurance, at our expense, to protect us and/or any director, officer, employee or agent of our corporation or another entity, trust or other enterprise against any expense, liability or loss, whether or not we would have the power to indemnify such person against such expense, liability or loss under the DGCL.

Any repeal or amendment of provisions of our bylaws affecting indemnification rights, whether by our board of directors, stockholders or by changes in applicable law, or the adoption of any other provisions inconsistent therewith, will (unless otherwise required by law) be prospective only, except to the extent such amendment or change in law permits us to provide broader indemnification rights on a retroactive basis, and will not in any way diminish or adversely affect any right or protection existing thereunder with respect to any act or omission occurring prior to such repeal or amendment or adoption of such inconsistent provision.

We will enter into indemnification agreements with each of our current directors and executive officers. These agreements will require us to indemnify these individuals to the fullest extent permitted under Delaware law against liabilities that may arise by reason of their service to us, and to advance expenses incurred as a result of any proceeding against them as to which they could be indemnified. We also intend to enter into indemnification agreements with our future directors and executive officers.

Under the Underwriting Agreement, the underwriters are obligated, under certain circumstances, to indemnify directors and officers of the registrant against certain liabilities, including liabilities under the Securities Act of 1933, as amended, or the Securities Act. Reference is made to the form of Underwriting Agreement to be filed as Exhibit 1.1 to this Registration Statement.

Item 15. Recent Sales of Unregistered Securities.

In exchange for the contribution by DB Holdings of all of the outstanding equity interests in Windsor Permian to us prior to the completion of this offering, we will issue shares of our common stock to DB Holdings. In addition, prior to the closing of this offering, we will issue shares of our common stock to Gulfport in connection with the Gulfport contribution.

The shares of our common stock described in this Item 15 will be issued in reliance upon the exemption from the registration requirements of the Securities Act provided by Section 4(2) of the Securities Act as sales by an issuer not involving any public offering.

Item 16. Exhibits and Financial Statement Schedules.

(A) Exhibits:

Exhibit Number	Number Description
1.1***	Form of Underwriting Agreement.
3.1*	Certificate of Incorporation of the Company.
3.2***	Form of proposed Amended and Restated Certificate of Incorporation to be effective immediately upon the closing of the offering made pursuant to this registration statement.
3.3*	Bylaws of the Company.
3.4***	Form of proposed Bylaws to be effective immediately upon the closing of the offering made pursuant to this registration statement.

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Exhibit Number	Number Description
4.1***	Specimen Certificate for shares of common stock, par value $0.01 per share, of the Company.
4.2**	Registration Rights Agreement by and among the Company and DB Energy Holdings LLC.
4.3**	Form of Investor Rights Agreement by and between the Company and Gulfport Energy Corporation.
5.1***	Opinion of Akin Gump Strauss Hauer & Feld LLP.
10.1*	Credit Agreement, dated as of October 15, 2010, by and among Windsor Permian LLC, as borrower, BNP Paribas, as administrative agent, and the lenders party thereto.
10.2*	First Amendment to Credit Agreement, dated as of January 31, 2011, by and among Windsor Permian LLC, as borrower, BNP Paribas, as administrative agent, and the lenders party thereto.
10.3*	Second Amendment to Credit Agreement, dated as of August 4, 2011, by and among Windsor Permian LLC, as borrower, BNP Paribas, as administrative agent, and the lenders party thereto.
10.4*	Third Amendment to Credit Agreement, dated as of October 14, 2011, by and among Windsor Permian LLC, as borrower, BNP Paribas, as administrative agent, and the lenders party thereto.
10.5*	Fourth Amendment to Credit Agreement, dated as of December 30, 2011, by and among Windsor Permian LLC, as borrower, BNP Paribas, as administrative agent, and the lenders party thereto.
10.6**	Shared Services Agreement, dated as of March 1, 2008, by and between Windsor Energy Resources LLC and Windsor Permian LLC.
10.7***	Lease Agreement, dated as of April 19, 2011, by and between Fasken Midland, LLC and Windsor Permian LLC.
10.8**	Lease Amendment No. 1 to Lease Agreement, dated as of June 6, 2011, by and between Fasken Midland, LLC and Windsor Permian LLC.
10.9**	Lease Amendment No. 2 to Lease Agreement, dated as of August 5, 2011, by and between Fasken Midland, LLC and Windsor Permian LLC.
10.10**	Lease Amendment No. 3 to Lease Agreement, dated as of September 28, 2011, by and between Fasken Midland, LLC and Windsor Permian LLC.
10.11**	Lease Amendment No. 4 to Lease Agreement, dated February 6, 2012, by and between Fasken Midland, LLC and Windsor Permian LLC.
10.12***	Equity Incentive Plan.
10.13***	Form of Stock Option Agreement.
10.14***	Form of Restricted Stock Agreement.
10.15***	Form of Director and Officer Indemnification Agreement.
10.16**	Form of Advisory Services Agreement by and between Diamondback Energy, Inc. and Wexford Capital LP.
10.17***	Contribution Agreement by and between the Company and DB Energy Holdings LLC.
10.18**	Contribution Agreement, dated May 7, 2012, by and between the Company and Gulport Energy Corporation.
10.19**	Master Drilling Agreement, dated January 1, 2012, by and between Windsor Permian LLC and Bison Drilling and Field Services LLC.
10.20**	Gas Purchase Agreement, dated May 1, 2009, by and between Windsor Permian LLC and Feagan Gathering Company.
10.21**	Amendment to Gas Purchase Agreement, dated July 1, 2011, by and between Windsor Permian LLC and MidMar Gas LLC.
10.22**	Amendment to Gas Purchase Agreement, dated January 11, 2012, by and between Windsor Permian LLC and MidMar Gas LLC.

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Exhibit Number	Number Description
21.1***	List of Significant Subsidiaries of the Company.
23.1**	Consent of Grant Thornton LLP.
23.2**	Consent of Pinnacle Energy Services, LLC.
23.3**	Consent of Ryder Scott Company.
23.4***	Consent of Akin Gump Strauss Hauer & Feld LLP (included in Exhibit 5.1).
24.1*	Power of Attorney.

* Previously filed.
** Filed herewith.
*** To be filed by amendment.
Management contract, compensatory plan or arrangement.
(B) Financial Statement Schedules.

All schedules are omitted because the required information is (i) not applicable, (ii) not present in amounts sufficient to require submission of the schedule or (iii) included in our financial statements and the accompanying notes included in the prospectus to this Registration Statement.

Item 17. Undertakings.

The undersigned Registrant hereby undertakes to provide to the underwriters at the closing specified in the underwriting agreements, certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification by the Registrant for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the Registrant pursuant to the foregoing provisions, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer, or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer, or controlling person in connection with the securities being registered hereunder, the Registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The Registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this Registration Statement in reliance upon Rule 430A and contained in a form of prospectus filed by the Registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this Registration Statement as of the time it was declared effective.

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the Registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Midland, State of Texas, on May 7, 2012.

DIAMONDBACK ENERGY, INC.

By: /s/ Travis D. Stice
Travis Stice

Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, this Registration Statement has been signed by the following persons in the capacities indicated on May 7, 2012.

Signature	Title
/s/ Travis D. Stice Travis D. Stice	Chief Executive Officer (Principal Executive Officer)
/s/ Teresa L. Dick Teresa L. Dick	Chief Financial Officer (Principal Financial and Accounting Officer)
* Steven E. West	Director

* By: /s/ Travis D. Stice
Travis D. Stice
Attorney-in-Fact

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