

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
(State or other jurisdiction of

1311

45-4502447
(I.R.S. Employer

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incorporation or organization)

(Primary Standard Industrial Classification
Code Number)

Identification Number)

500 West Texas

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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

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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	<input type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input checked="" type="checkbox"/> (Do not check if a smaller reporting company)	Smaller reporting company	<input type="checkbox"/>

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 uncertainty 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 Wells ⁽²⁾	2012 Budget		Estimated Net Proved Reserves at December 31, 2011		Average Daily Production (BOE/d) ⁽³⁾
			Gross	Net		Net Wells ⁽²⁾	Capex (In millions)	MBOE	% Developed	
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.

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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 processes. 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.

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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

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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.

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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 (exercised in full)	shares if the underwriters option to purchase additional shares is
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Common stock offered by the selling stockholders	shares (exercised in full)	shares if the underwriters option to purchase additional shares is
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Common stock to be outstanding immediately after completion of this offering	shares
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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.
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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 <i>Use of Proceeds</i> on page 42 of this prospectus.
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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.
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NASDAQ Global Market symbol	FANG
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Risk Factors	You should carefully read and consider the information beginning on page 14 of this prospectus set forth under the heading <i>Risk Factors</i> and all other information set forth in this prospectus before deciding to invest in our common stock.
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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.

Table of Contents**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	2011	Historical Year Ended December 31, 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	2011	Historical As of December 31, 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	2011	Historical As of December 31, 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.

Table of Contents**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.

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RISK FACTORS

An investment in our common stock involves a high degree of risk. You should carefully consider the following risks and all of the other information contained in 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

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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

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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

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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

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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.

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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

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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.

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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

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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.

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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

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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 by Bison Drilling and Field Services, LLC, real property leased by us from Fasken Midland, LLC and certain administrative services provided to us by Everest Operations Management LLC. Each of these entities is either controlled by or affiliated with Wexford, and the resolution of any conflicts that may arise in connection with such related party transactions, including pricing, duration or other terms of service, may not always be in our or our stockholders' best interests because Wexford may have the ability to influence the outcome of these conflicts. For a discussion of potential conflicts, see *Risks Related to this Offering and our Common Stock* *Our two largest stockholders control a significant percentage of our common stock, and their interests may conflict with those of our other stockholders* on page 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

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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;

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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.

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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

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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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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 (in thousands)	Pro Forma As Adjusted ⁽²⁾
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

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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.

Table of Contents**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.

Table of Contents**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, 2007
	2011	2010	2009	2008	
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, 2007
	2011	2010	2009	2008	
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

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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, 2007
	2011	2010	2009	2008	
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.

Table of Contents**Diamondback Energy, Inc.****Unaudited Pro Forma Condensed Consolidated Balance Sheets****December 31, 2011**

	Windsor Permian Historical	Windsor UT Historical	Pro Forma Adjustments	Pro Forma
Assets				
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.

Table of Contents**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 Natural Gas			Gulfport Contribution Historical Natural Gas			Windsor UT Historical Natural Gas			Total Pro Forma Natural Gas		
	Oil (MBbls)	Liquids (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Liquids (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Liquids (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	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

Table of Contents**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;

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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

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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 Unweighted Arithmetic Average First-Day-of-the-Month Prices	2010	2009
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,

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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%.

Table of Contents**Results of Operations**

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

	2011	Year Ended December 31, 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.

Table of Contents**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		Volume	Original Strike Price	December 31, 2011 Fair Value
Crude Oil Swaps:		(Bbls)	(per Bbl)	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		Volume	Original Strike Price	Lock-in Price	December 31, 2011 Fair Value	December 31, 2010 Fair Value
Oil Swaps:		(Bbls)	(per Bbl)	(per Bbl)	Liability	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		Volume	Original Strike Price	Lock-in Price	December 31, 2011 Fair Value	December 31, 2010 Fair Value
Oil Swaps:		(Bbls)	(per Bbl)	(per Bbl)	Asset	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.

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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.

				December 31,		
				2010	2009	
Description and Production Period		Volume (Bbls)	Original Strike Price (per Bbl)	Lock-in Price (per Bbl)	Fair Value Liability	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	Lock-in Price (per Bbl)	December 31,	
		Price (per Bbl)		2010 Fair Value Asset	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.

Table of Contents**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

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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:

	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
	Payments Due By Year (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

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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

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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

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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.

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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.

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BUSINESS

General

Overview

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

We began operations in December 2007 with our acquisition of 4,174 net acres with production at the time of acquisition of approximately 800 BOE/d from 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

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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 uncertainty 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.

Basin	Net Acreage	Average Working Interest	Identified Potential Drilling Locations ⁽¹⁾		Gross Wells ⁽²⁾	2012 Budget		Estimated Net Proved Reserves at December 31, 2011		Average Daily Production (BOE/d) ⁽³⁾
			Gross	Net		Net Wells ⁽²⁾	Capex (In millions)	MBOE	% Developed	
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

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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 processes. 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.

Basin	Net Acreage	Average Working Interest	Identified Potential Drilling Locations ⁽¹⁾		2012 Budget			Estimated Net Proved Reserves at December 31, 2011		Average Daily Production (BOE/d) ⁽³⁾
			Gross	Net	Gross Wells ⁽²⁾	Net Wells ⁽²⁾	Capex (In millions)	MBOE	% Developed	
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.

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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

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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

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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

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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	2011	Historical Year Ended December 31, 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%

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- (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	2011	Historical Year Ended December 31, 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:

Basin	Developed Acreage ⁽¹⁾		Undeveloped Acreage ⁽²⁾		Total Acreage	
	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.

Basin	Remaining 2012		2013		2014		2015		2016	
	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

Table of Contents**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.

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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

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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.

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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 ratable 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.

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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

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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.

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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.

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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.

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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

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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

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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;

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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

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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

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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.

Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable ⁽¹⁾	Option Awards 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

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- (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

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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.

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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 inter vivos 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:

Name	Termination Without Cause or Upon Death or Disability ⁽¹⁾⁽²⁾				Resignation for Good Reason ⁽³⁾				Change of Control			
	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.

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- (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.

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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.

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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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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.

Name of Beneficial Owner	Shares Beneficially Owned Prior to Offering		Number of Shares Offered	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	
	Number	Percentage		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

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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;

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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.

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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.

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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.

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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.

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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

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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.

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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.

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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.

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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]

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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

	Developed		Proved	
	Producing	Non-Producing	Undeveloped	Total Proved
<u>Net Remaining Reserves</u>				
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
<u>Income Data (\$M)</u>				
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

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	Total Probable Undeveloped	Total Possible Undeveloped
<u>Net Remaining Reserves</u>		
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
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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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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			
Discount Rate	Total	As of December 31, 2011 (\$M)	
		Total	Total
Percent	Proved	Probable	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.

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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

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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.

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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	\$ 96.19/Bbl	\$ 93.09/Bbl	\$ 92.89/Bbl	\$ 92.85/Bbl
	NGLs	Cushing WTI	\$ 61.97/Bbl	\$ 56.33/Bbl	\$ 57.02/Bbl	\$ 56.91/Bbl
	Gas	Cushing 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.

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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

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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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]

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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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PETROLEUM RESERVES DEFINITIONS

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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

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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

	Producing	Developed Non-Producing	Proved Undeveloped	Total Proved
<u>Net Remaining Reserves</u>				
Oil/Condensate MBbl	109	34	1,240	1,383
Plant Products MBbl	23	7	256	286
Gas MCF	76	23	834	933
MBOE	145	45	1,635	1,825
<u>Income Data (\$M)</u>				
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

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	Total Probable Undeveloped
<u>Net Remaining Reserves</u>	
Oil/Condensate MBbl	2,583
Plant Products MBbl	533
Gas MMCF	1,737
MBOE	3,406
<u>Income Data (\$M)</u>	
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)	
	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.

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January 20, 2012

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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.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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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

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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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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	Oil/Condensate	WTI Cushing	\$96.19/Bbl	\$92.99/Bbl	\$92.99/Bbl
United States	NGLs	WTI Cushing	\$61.97/Bbl	\$56.74/Bbl	\$56.74/Bbl
		Henry Hub/Colorado Interstate			
	Gas		\$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

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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.

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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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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

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PETROLEUM RESERVES DEFINITIONS

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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*

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PETROLEUM RESERVES DEFINITIONS

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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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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

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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
 1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235 TELEPHONE(713) 651-9191
January 13, 2012

FAX (713) 651-0849

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

	Producing	Developed Non-Producing	Proved Undeveloped	Total Proved
<u>Net Remaining Reserves</u>				
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
<u>Income Data (\$M)</u>				
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

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Discounted FNI @ 10%	\$ 84,900	\$ 14,551	\$ 102,837	\$ 202,288
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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 (Mbbbl). 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

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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

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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
		Henry Hub		
	Gas	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.

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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.

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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

[SEAL]

DPG/pl

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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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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

Table of Contents**Windsor Permian LLC and Subsidiaries****Consolidated Balance Sheets**

	December 31,	
	2011	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.

Table of Contents**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.

Table of Contents**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

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Cash and cash equivalents at end of period	\$ 6,802,389	\$ 4,089,745	\$ 2,430,308
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Supplemental cash flow information

Interest paid, net of capitalized interest	\$ 2,265,005	\$ 600,194	\$
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Asset retirement obligation incurred, including changes in estimate	\$ 288,640	\$ 208,083	\$ 79,666
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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.

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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.

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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.

Table of Contents**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

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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

Table of Contents**Windsor Permian LLC and Subsidiaries****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	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.

Table of Contents**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

Table of Contents**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:

	46	(15)	407%			
Total Adjusted EBITDA	\$ 95	\$ 114	(17)%	\$ 269	\$ 294	(9)%
Adjusted EBITDA Margin by Segment (2):						
Hotel	16%	31%		23%	33%	
Non-Hotel	35%	15%		16%	(7)%	

(1) Included in Adjusted EBITDA is a general and administrative expense allocation for each segment, which is based on the segment's percentage of our total personnel costs, excluding stock-based compensation. See "Note 11: Segment Information" in the notes to our unaudited condensed consolidated financial statements for more information.

(2) We define "Adjusted EBITDA Margin by Segment", as Adjusted EBITDA by segment divided by revenue by segment.

Hotel Segment

Our Hotel segment revenue decreased by \$8 million during the three months ended September 30, 2017, when compared to the same period in 2016, primarily due to a decrease of \$11 million in TripAdvisor-branded click-based and transaction revenue during the three months ended September 30, 2017, partially offset by an increase of \$3 million in TripAdvisor-branded display-based advertising and subscription revenue, all of which are discussed below. Our Hotel segment revenue increased by \$13 million during the nine months ended September 30, 2017, when compared to the same period in 2016, primarily due to an increase of \$23 million in TripAdvisor-branded click-based and transaction revenue during the nine months ended September 30, 2017, which was primarily offset by a decrease of \$11 million in other hotel revenue during the nine months ended September 30, 2017, all of which are discussed below.

Adjusted EBITDA and Adjusted EBITDA margin in our Hotel segment decreased by \$48 million and decreased to 16%, during the three months ended September 30, 2017, respectively, when compared to the same period in 2016, primarily due to costs of our brand advertising campaign, or television campaign, which launched in June 2017. Adjusted EBITDA and Adjusted EBITDA margin in our Hotel segment decreased by \$86 million and decreased to 23%, during the nine months ended September 30, 2017, respectively, when compared to the same period in 2016, primarily due to costs related to our television campaign, and also due to increased SEM and other online traffic acquisition costs during the first six months of 2017. During the three months ended September 30, 2017, our SEM and other online traffic costs were essentially flat, when compared to the same period in 2016, as we reduced our spending in online marketing channels and increased our spending in connection with our television campaign during the third quarter of 2017.

The following is a detailed table showing the revenue sources within our Hotel segment:

	Three months ended September 30, 2017 2016 (in millions)			% Change 2017 vs. 2016			Nine months ended September 30, 2017 2016 (in millions)			% Change 2017 vs. 2016		
Hotel:												
TripAdvisor-branded click-based and transaction	\$ 195	\$ 206		(5)%	\$ 619	\$ 596		4	%		
TripAdvisor-branded display-based advertising and subscription	76	73		4	%	215	214		0	%		
Other hotel revenue	41	41		0	%	118	129		(9)%		
Total Hotel revenue	\$ 312	\$ 320		(3)%	\$ 952	\$ 939		1	%		

TripAdvisor-branded Click-based and Transaction Revenue

TripAdvisor-branded click-based and transaction revenue includes cost-per-click-based advertising revenue from our TripAdvisor-branded websites as well as transaction-based revenue from our hotel instant booking feature. For the three and nine months ended September 30, 2017, 63% and 65%, respectively, of our total Hotel segment revenue came from our TripAdvisor-branded click-based and transaction revenue. For the three and nine months ended September 30, 2016, 64% and 63%, respectively, of our total Hotel segment revenue was derived from our TripAdvisor-branded click-based and transaction revenue. TripAdvisor-branded click-based and transaction revenue during the three months ended September 30, 2017 decreased \$11 million, when compared to the same period in 2016, primarily due to a decrease of 11% in revenue per hotel shopper, which was partially offset by an increase of 7% in average monthly unique hotel shoppers during the three months ended September 30, 2017, which is explained below. TripAdvisor-branded click-based and transaction revenue during the nine months ended September 30, 2017 increased \$23 million, when compared to the same period in 2016, primarily due to an increase of 9% in average monthly unique hotel shoppers during the nine months ended September 30, 2017, which was partially offset by a decrease of 4% in revenue per hotel shopper, which is explained below.

Our largest source of Hotel segment revenue is click-based advertising revenue from our TripAdvisor-branded websites, which include links to our partners' sites and contextually-relevant branded and related text links. Click-based advertising is generated primarily through our metasearch auction, a description of which follows. Our click-based advertising partners are predominantly OTAs and hoteliers. Click-based advertising is generally priced on a cost-per-click, or CPC, basis, with payments from advertisers based on the number of users who click on each type of link or, in other words, the conversion of a hotel shopper to a paid click. CPC is the price that a partner is willing to pay us for a hotel shopper lead and is determined in a competitive process that enables our partners to use our proprietary, automated bidding system to submit CPC bids to have their rates and availability listed on our site. When a partner submits a CPC bid, they are agreeing to pay the amount of that bid each time a user subsequently clicks on the link to the partner's website. Bids can be submitted periodically – as often as daily – on a property-by-property basis. Primary factors used to determine the placement of partner links on our site include, but are not limited to, room night price, the size of the bid relative to other bids, and other variables. CPCs are generally lower in markets outside the U.S. market, and hotel shoppers visiting via mobile phones currently monetize at a significantly lower rate than hotel shoppers visiting via desktop or tablet.

Our Hotel segment transaction-based revenue is comprised of revenue from our hotel instant booking feature, which enables the merchant of record, generally an OTA or hotel partner, to pay a commission to TripAdvisor for a user that completes a hotel reservation on our website. Instant booking revenue is currently recognized under two different models: the transaction model and the consumption model. Under the consumption model, which currently represents the majority of our instant booking revenue, commission revenue is not recorded until such time as the traveler completes their stay, at which time our consumption partner is liable to us for commission payment. Under the transaction model commission revenue is recorded at the time a traveler books a hotel reservation on our site, as our transaction partner is liable for commission payments to us upon booking and the partner assumes the cancellation risk. OTA and hotel partner placement, as well as comparative hotel prices available to the traveler in the booking process under both models, is determined by a bidding process within our proprietary automated bidding system, that takes into account a number of variables, primarily hotel room prices, but also including other factors, such as conversion rates and commission rates, depending on the specific hotel selected. Instant booking commissions are primarily a function of average gross booking value generated from hotel reservations, cancellation rates experienced, and commission rates negotiated with each of our partners.

The key drivers of TripAdvisor-branded click-based and transaction revenue include growth in average monthly unique hotel shoppers and revenue per hotel shopper growth, the latter of which measures how effectively we convert our hotel shoppers into revenue. We measure performance by calculating revenue per hotel shopper on an aggregate

basis by dividing total TripAdvisor-branded click-based and transaction revenue by total average monthly unique hotel shoppers on TripAdvisor-branded websites for the periods presented.

While we believe that total traffic growth, or growth in monthly visits from unique visitors, is reflective of our overall brand growth, we also track and analyze sub-segments of our traffic and their correlation to revenue generation and utilize data regarding hotel shoppers as one of the key indicators of revenue growth. Hotel shoppers are visitors who view either a listing of hotels in a city or on a specific hotel page. The number of hotel shoppers tends to vary based on seasonality of the travel industry and general economic conditions, as well as other factors outside of our control. Given these factors, as well as the trend towards increased usage on mobile phones and international expansion, quarterly and annual hotel shopper growth is a difficult metric to forecast.

The below table summarizes our revenue per hotel shopper calculation and growth rate, in aggregate, for the periods presented (in millions, except calculated revenue per hotel shopper and percentages):

	Three months ended			Nine months ended			
	September 30, 2017	September 30, 2016	% Change 2017 vs. 2016	September 30, 2017	September 30, 2016	% Change 2017 vs. 2016	
Revenue per hotel shopper:							
TripAdvisor-branded click-based and transaction revenue	\$ 195	\$ 206	(5)%	\$ 619	\$ 596	4 %	
Divided by: Total average unique monthly hotel shoppers for the quarter	490	458	7 %	1,398	1,286	9 %	
	\$ 0.40	\$ 0.45	(11)%	\$ 0.44	\$ 0.46	(4)%	

Revenue per hotel shopper decreased 11% during the three months ended September 30, 2017, when compared to the same period in 2016, according to our internal log files. The decrease was driven primarily by lower CPCs received in our click-based metasearch auction, as we observed partners increase marketing efficiency on our channel during the third quarter of 2017 resulting in lower CPC bids in all geographic areas, as well as the general trend of a greater percentage of hotel shoppers visiting TripAdvisor-branded websites and apps on mobile phones.

Revenue per hotel shopper decreased 4% during the nine months ended September 30, 2017, when compared to the same period in 2016, according to our internal log files. The decrease was driven primarily by the factors noted above, as well as by factors that primarily impacted us during the first six months of 2017, including dilution from product testing related to the second-quarter 2017 launch of our redesigned website and applications, foreign currency fluctuations and the timing of our instant booking feature rollout in certain non-U.S. markets during the first half of 2016, partially offset by strong growth in U.S. revenue per hotel shopper during the first six months of 2017.

Our aggregate average monthly unique hotel shoppers on TripAdvisor-branded websites increased by 7% and 9% during the three and nine months ended September 30, 2017, respectively, when compared to the same periods in 2016, according to our internal log files. The increase in hotel shoppers for the three and nine months ended September 30, 2017 is primarily due to the success in our paid online marketing strategy, as well as the general trend of an increasing number of hotel shoppers visiting our websites and apps on mobile phones, partially offset by increased brand advertising spend related to our television campaign as part of our marketing mix, which we believe has a longer term return in comparison to online marketing spend.

TripAdvisor-branded Display-based Advertising and Subscription Revenue

For the three and nine months ended September 30, 2017, 24% and 23%, respectively, of our Hotel segment revenue came from our TripAdvisor-branded display-based advertising and subscription revenue, which primarily consists of revenue from display-based advertising and subscription-based hotel advertising revenue. For both the three and nine months ended September 30, 2016, 23% of our Hotel segment revenue was derived from our TripAdvisor-branded display-based advertising and subscription revenue.

Our TripAdvisor-branded display-based advertising and subscription revenue increased by \$3 million or 4%, during the three months ended September 30, 2017, when compared to the same period in 2016. Display-based advertising revenue increased primarily due to an increase in impressions sold, partially offset by a slight decrease in pricing and the general trend of increasing traffic visiting our websites and apps on mobile phones. While we continue to focus on new product initiatives to drive growth, our subscription revenue was flat primarily as we work to enhance our product offering to hoteliers and increase our sales pipeline in this business, as well as hotel industry consolidation. Our TripAdvisor-branded display-based advertising and subscription revenue increased slightly by \$1 million or 0%,

during the nine months ended September 30, 2017, when compared to the same period in 2016.

Other Hotel Revenue

For the three and nine months ended September 30, 2017, 13% and 12%, respectively, of our Hotel segment revenue came from other hotel revenue. For the three and nine months ended September 30, 2016, 13% and 14%, respectively, of our Hotel segment revenue was derived from other hotel revenue. Our other hotel revenue primarily includes revenue from non-TripAdvisor branded websites, such as bookingbuddy.com, cruisecritic.com, and onetime.com, including click-based advertising revenue, display-based advertising revenue and room reservations sold through these websites. Our other hotel revenue was flat and decreased by \$11 million during the three and nine months ended September 30, 2017, respectively, when compared to the same periods in 2016, primarily due to increased focus on return on marketing spend from paid marketing channels within this revenue stream.

Non-Hotel Segment

Our Non-Hotel segment revenue increased by \$26 million or 26%, and \$58 million or 26% during the three and nine months ended September 30, 2017, respectively, when compared to the same periods in 2016, primarily driven by increased bookable supply, user demand, and increased bookings in our Attractions and Restaurants businesses.

Strong revenue growth in our Attractions business has been driven by the following factors: growth in bookings sourced by TripAdvisor, growth in bookable products, which leads to better consumer choice, as well as by growth in free and paid traffic sources. Another contributing factor is the improved shopping experience from the introduction of new features, such as attractions instant booking for mobile phone, which enables users to purchase tickets and tours seamlessly without leaving the mobile app. These factors are all contributing to more consumer choice and continued revenue growth as a result of increased bookings. Similarly, in our Restaurants business, continued strong revenue growth can be attributed to increased bookings in our most established markets, growth in mobile bookings, a continually improving user experience and an increase in bookable supply of restaurant listings during the three and nine months ended September 30, 2017, respectively, when compared to the same periods in 2016.

Non-Hotel segment Adjusted EBITDA increased \$29 million and \$61 million during the three and nine months ended September 30, 2017, respectively, when compared to the same periods in 2016. This increase was primarily due to increased revenue growth, for the reasons noted above, and increased efficiencies in paid online marketing channels and other operational efficiencies in our Attractions business, partially offset primarily by increased personnel and overhead costs to support growth in this segment for the three and nine months ended September 30, 2017.

Revenue by Geography

The following table presents our consolidated revenue by geographic region. Revenue by geography is based on the geographic location of our websites.

	Three months ended September 30, 2017 2016 % Change 2017 vs. 2016 (in millions)				Nine months ended September 30, 2017 2016 % Change 2017 vs. 2016 (in millions)			
Revenue by geographic region:								
United States	\$ 245	\$ 225	9	%	\$ 699	\$ 627	11	%
Europe	124	123	1	%	331	329	1	%
ROW	70	73	(4)%	205	208	(1)%
Total	\$ 439	\$ 421	4	%	\$ 1,235	\$ 1,164	6	%

(1) In the first quarter of 2017, we reclassified Canada, Middle East, Africa, Asia-Pacific (“APAC”) and Latin America (“LATAM”) into rest of world (“ROW”) when presenting our revenue by geographic region. Prior period amounts were reclassified to conform to the current presentation. This change had no effect on our consolidated financial statements in any reporting period.

Our U.S. revenue increased \$20 million or 9%, during the three months ended September 30, 2017, when compared to the same period in 2016. U. S. revenue represented 56% and 53% of total revenue during the three months ended September 30, 2017 and 2016, respectively. This increase in the U.S. was due primarily to growth in our Attractions business. Revenue outside of the U.S., or non-U.S. revenue, decreased \$2 million, or 1%, during the three months ended September 30, 2017, when compared to the same period in 2016. Non-U.S. revenue represented 44% and 47% of total revenue during the three months ended September 30, 2017 and 2016, respectively. The decline in our

non-U.S. revenue, as a percentage of total revenue during this period was primarily due to growth in our Attractions business in the U.S and a higher growth rate in mobile phone hotel shoppers and a higher percentage of total hotel shoppers from mobile devices in non-U.S. markets during the period.

Our U.S. revenue increased \$72 million or 11%, during the nine months ended September 30, 2017, when compared to the same period in 2016. U. S. revenue represented 57% and 54% of total revenue during the nine months ended September 30, 2017 and 2016, respectively. This increase was due to an increase in U.S. TripAdvisor-branded click-based and transaction revenue, driven by growth in U.S. revenue per hotel shopper during the nine months ended September 30, 2017, when compared to the same period in 2016, as well as growth in our Attractions business. Revenue outside of the U.S., or non-U.S. revenue, decreased \$1 million or 0%, during the nine months ended September 30, 2017, when compared to the same period in 2016. Non-U.S. revenue represented 43% and 46% of total revenue during the nine months ended September 30, 2017 and 2016, respectively. The decline in our non-U.S. revenue, as a percentage of total revenue during these periods, was primarily driven by the factors noted above, as well as, foreign currency fluctuations and the timing of our instant booking feature rollout in certain non-U.S. markets during the first half of 2016.

Consolidated Expenses

Cost of Revenue

Cost of revenue consists of expenses that are directly related or closely correlated to revenue generation, including direct costs, such as ad serving fees, flight search fees, credit card fees and other transaction costs, and data center costs. In addition, cost of revenue includes personnel and overhead expenses, including salaries, benefits, stock-based compensation expense and bonuses for certain customer support personnel who are directly involved in revenue generation.

	Three months ended				Nine months ended			
	September 30, 2017	2016	% Change 2017 vs. 2016		September 30, 2017	2016	% Change 2017 vs. 2016	
	(in millions)				(in millions)			
Direct costs	\$ 15	\$ 14	7	%	\$ 42	\$ 40	5	%
Personnel and overhead	5	5	0	%	14	15	(7)%
Total cost of revenue	\$ 20	\$ 19	5	%	\$ 56	\$ 55	2	%
% of revenue	4.6 %	4.5 %			4.5 %	4.7 %		

Cost of revenue increased \$1 million during both the three and nine months ended September 30, 2017 when compared to the same periods in 2016, primarily due to increased direct costs from merchant credit card and transaction fees in our Non-Hotel segment, as a result of revenue growth.

Selling and Marketing

Selling and marketing expenses primarily consist of direct costs, including traffic generation costs from SEM and other online traffic acquisition costs, syndication costs and affiliate program commissions, social media costs, brand advertising, television and other offline advertising, and public relations. In addition, our sales and marketing expenses consist of indirect costs such as personnel and overhead expenses, including salaries, commissions, benefits, stock-based compensation expense and bonuses for sales, sales support, customer support and marketing employees.

	Three months ended				Nine months ended			
	September 30, 2017	2016	% Change 2017 vs. 2016		September 30, 2017	2016	% Change 2017 vs. 2016	
	(in millions)				(in millions)			
Direct costs	\$195	\$159	23	%	\$526	\$430	22	%
Personnel and overhead	52	51	2	%	157	154	2	%
Total selling and marketing	\$247	\$210	18	%	\$683	\$584	17	%
% of revenue	56.3%	49.9%			55.3%	50.2%		

Direct selling and marketing costs increased \$36 million during the three months ended September 30, 2017, when compared to the same period in 2016, driven primarily by an increase of \$42 million in costs incurred related to the launch of our television campaign in June of 2017, which is recorded in our Hotel segment, partially offset by a decrease in other advertising costs. SEM and other online traffic acquisition costs were essentially flat during the three months ended September 30, 2017, when compared to the same period in 2016, as we shifted marketing spend to our

television campaign.

Direct selling and marketing costs increased \$96 million during the nine months ended September 30, 2017, when compared to the same period in 2016, driven primarily by an increase of \$58 million in costs incurred related to the launch of our television campaign in June of 2017, which is recorded in our Hotel segment, as well as an increase in SEM and other online traffic acquisition costs of \$43 million, driven by our Hotel segment, partially offset by a decrease in other advertising costs.

Technology and Content

Technology and content expenses consist primarily of personnel and overhead expenses, including salaries and benefits, stock-based compensation expense and bonuses for salaried employees and contractors engaged in the design, development, testing, content support, and maintenance of our websites and mobile apps. Other costs include licensing, maintenance expense, computer supplies, telecom costs, content translation costs, and consulting costs.

	Three months ended				Nine months ended		
	September 30, 2017	2016	% Change 2017 vs. 2016		September 30, 2017	2016	% Change 2017 vs. 2016
	(in millions)				(in millions)		
Personnel and overhead	\$55	\$56	(2 %)		\$166	\$161	3 %
Other	6	6	0 %		18	24	(25 %)
Total technology and content	\$61	\$62	(2 %)		\$184	\$185	(1 %)
% of revenue	13.9%	14.7%			14.9%	15.9%	

Technology and content costs decreased \$1 million during both the three and nine months ended September 30, 2017, respectively, when compared to the same period in 2016. Personnel and overhead costs decreased \$1 million during the three months ended September 30, 2017, when compared to the same period in 2016, primarily due to a decrease in contingent staff costs, partially offset by an increase in personnel costs to support our mobile phone and website initiatives, as well as to support business growth. Personnel and overhead costs increased \$5 million during the nine months ended September 30, 2017, when compared to the same period in 2016, primarily to support our mobile phone and website initiatives, as well as to support business growth, partially offset by a decrease in contingent staff costs. Other costs decreased by \$6 million during the nine months ended September 30, 2017, when compared to the same period in 2016, primarily due to a decrease in content translation costs.

General and Administrative

General and administrative expenses consist primarily of personnel and related overhead costs, including personnel engaged in executive leadership, finance, legal, and human resources, as well as stock-based compensation expense for those same personnel. General and administrative costs also include professional service fees and other fees including audit, legal, tax and accounting, and other costs including bad debt expense, non-income taxes, such as sales, use and other non-income related taxes, and charitable contributions.

	Three months ended				Nine months ended		
	September 30, 2017	2016	% Change 2017 vs. 2016		September 30, 2017	2016	% Change 2017 vs. 2016
	(in millions)				(in millions)		
Personnel and overhead	\$ 29	\$ 27	7 %		\$ 85	\$ 77	10 %
Professional service fees and other	13	11	18 %		30	33	(9 %)
Total general and administrative	\$ 42	\$ 38	11 %		\$ 115	\$ 110	5 %
% of revenue	9.6 %	9.0 %			9.3 %	9.5 %	

General and administrative costs increased \$4 million and \$5 million during the three and nine months ended September 30, 2017, respectively, when compared to the same periods in 2016. Personnel and overhead costs increased \$2 million and \$8 million during the three and nine months ended September 30, 2017, respectively, when compared to the same periods in 2016, primarily related to an increase in stock-based compensation of \$3 million and \$6 million, respectively. Professional service fees and other increased \$2 million during the three months ended September 30, 2017, when compared to the same period in 2016, primarily due to an increase in bad debt costs and non-income taxes, partially offset by a decrease in consulting costs. Professional service fees and other decreased \$3 million during the nine months ended September 30, 2017, when compared to the same period in 2016, primarily due to a decrease in consulting costs and non-income taxes, partially offset by an increase in bad debt costs.

Depreciation

Depreciation expense consists of depreciation on computer equipment, leasehold improvements, furniture, office equipment and other assets, our corporate headquarters building and amortization of capitalized software and website development costs.

	Three months ended September 30, 2017 2016 (in millions)		Nine months ended September 30, 2017 2016 (in millions)	
Depreciation	\$ 19	\$ 18	\$ 57	\$ 51
% of revenue	4.3 %	4.3 %	4.6 %	4.4 %

Depreciation expense increased \$1 million and \$6 million during the three and nine months ended September 30, 2017, respectively, when compared to the same periods in 2016, primarily due to increased amortization related to capitalized software and website development costs.

Amortization of Intangible Assets

Amortization consists of the amortization of purchased definite-lived intangibles.

	Three months ended September 30, 2017 2016 (in millions)		Nine months ended September 30, 2017 2016 (in millions)	
Amortization of intangible assets	\$ 8	\$ 8	\$ 25	\$ 23
% of revenue	1.8 %	1.9 %	2.0 %	2.0 %

Amortization of intangible assets remained flat during the three months ended September 30, 2017, when compared to the same periods in 2016. Amortization of intangible assets increased \$2 million during the nine months ended September 30, 2017, when compared to the same period in 2016, primarily due to incremental amortization from purchased indefinite lived intangibles related to our 2016 business acquisitions.

Interest Expense

Interest expense primarily consists of interest incurred, commitment fees and debt issuance cost amortization related to our 2015 Credit Facility, 2016 Credit Facility, and Chinese Credit Facilities, as well as interest on our financing obligation related to our corporate headquarters.

	Three months ended September 30, 2017 2016 (in millions)		Nine months ended September 30, 2017 2016 (in millions)	
Interest expense	\$ (4)	\$ (3)	\$ (11)	\$ (10)

Interest expense increased \$1 million during both the three and nine months ended September 30, 2017, when compared to the same periods in 2016, primarily due to an increase in interest incurred due to higher average outstanding borrowings and effective interest rates during the first nine months of 2017. Refer to “Note 6: Debt” in the notes to our unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q for additional information on our 2015 Credit Facility, 2016 Credit Facility, and Chinese Credit Facilities.

Interest Income and Other, Net

Interest income and other, net primarily consists of interest earned and amortization of discounts and premiums on our marketable securities, net foreign exchange gains and losses, and gains and losses on sales of our marketable securities and sale of businesses.

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2017	2016	2017	2016
	(in millions)		(in millions)	
Interest income and other, net	\$ -	\$ -	\$ 3	\$ -

Interest income and other, net remained flat and increased \$3 million during the three and nine months ended September 30, 2017, respectively, when compared to the same periods in 2016, primarily due higher transaction gains of \$2 million and \$5 million, respectively, as a result of the fluctuation of foreign exchange rates, partially offset by a loss of \$2 million related to one of our cost-method investments recognized during the three months ended September 30, 2017.

Provision for Income Taxes

	Three months ended September 30, 2017 2016		Nine months ended September 30, 2017 2016	
	(in millions)		(in millions)	
Provision for income taxes	\$13	\$8	\$42	\$27
Effective tax rate	34.2%	12.7%	39.3%	18.5%

For both the three and nine months ended September 30, 2017, respectively, the effective tax rate is greater than the federal statutory rate primarily due to valuation allowances on losses in jurisdictions outside the United States, recognition of stock compensation shortfalls, and a change in the relative mix of pretax income among jurisdictions. These same drivers also resulted in an increase in the effective tax rate for the three and nine months ended September 30, 2017, respectively, when compared to same periods in 2016.

Adjusted EBITDA

To provide investors with additional information regarding our financial results, we also disclose Adjusted EBITDA, which is a non-GAAP financial measure. A “non-GAAP financial measure” refers to a numerical measure of a company’s historical or future financial performance, financial position, or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP in such company’s financial statements.

Adjusted EBITDA is our segment profit measure and a key measure used by our management and board of directors to understand and evaluate the operating performance of our business and on which internal budgets and forecasts are based and approved. In particular, the exclusion of certain expenses in calculating Adjusted EBITDA can provide a useful measure for period-to-period comparisons of our core business. Accordingly, we believe that Adjusted EBITDA provides useful information to investors and others in understanding and evaluating our operating results in the same manner as our management and board of directors. We define Adjusted EBITDA as net income (loss) plus: (1) provision for income taxes; (2) other income (expense), net; (3) depreciation of property and equipment, including amortization of internal use software and website development; (4) amortization of intangible assets; (5) stock-based compensation and other stock-settled obligations; (6) goodwill, long-lived asset and intangible asset impairments; and (7) other non-recurring expenses and income.

Our use of Adjusted EBITDA has limitations as an analytical tool, and you should not consider it in isolation or as a substitute for analysis of our results reported in accordance with GAAP. Because of these limitations, you should consider Adjusted EBITDA alongside other financial performance measures, including net income and our other GAAP results.

Some of these limitations are:

- Adjusted EBITDA does not reflect our cash expenditures or future requirements for capital expenditures or contractual commitments;
- Adjusted EBITDA does not reflect changes in, or cash requirements for, our working capital needs;
- Adjusted EBITDA does not reflect the interest expense, or cash requirements necessary to service interest or principal payments on our debt;
- Adjusted EBITDA does not consider the potentially dilutive impact of stock-based compensation or other stock-settled obligations;
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Although depreciation and amortization are non-cash charges, the assets being depreciated and amortized may have to be replaced in the future, and Adjusted EBITDA does not reflect cash capital expenditure requirements for such replacements or for new capital expenditure requirements;

• Adjusted EBITDA does not reflect tax payments that may represent a reduction in cash available to us; and

• Other companies, including companies in our own industry, may calculate Adjusted EBITDA differently than we do, limiting its usefulness as a comparative measure.

The following table presents a reconciliation of Adjusted EBITDA to Net Income, the most directly comparable financial measure calculated and presented in accordance with GAAP, for the periods presented:

	Three months ended September 30, 2017		Nine months ended September 30, 2016	
	2017	2016	2017	2016
	(in millions)			
Net income	\$25	\$55	\$ 65	\$ 119
Add: Provision for income taxes	13	8	42	27
Add: Other expense (income), net	4	3	8	10
Add: Stock-based compensation	26	22	72	64
Add: Amortization of intangible assets	8	8	25	23
Add: Depreciation	19	18	57	51
Adjusted EBITDA	\$95	\$114	\$ 269	\$ 294

Related Party Transactions

For information on our relationship with Liberty TripAdvisor Holdings, Inc., refer to “Note 10: Related Party Transactions” in the notes to our unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q. We had no related party transactions with LTRIP during the three and nine months ended September 30, 2017 and 2016, respectively.

Stock-Based Compensation

Refer to “Note 3: Stock Based Awards and Other Equity Instruments” in the notes to our unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q for further information on current year equity award activity, including the issuance of 1,529,127 service-based stock options with a weighted average grant-date fair value per option of \$17.16 and 4,241,561 service-based RSUs with a weighted average grant-date fair value of \$42.65 during the nine months ended September 30, 2017.

Liquidity and Capital Resources

Our principal source of liquidity is cash flows generated from operations and cash, cash equivalents and marketable securities, although liquidity needs can also be met through drawdowns under our 2015 Credit Facility, 2016 Credit Facility, and Chinese Credit Facilities. As of September 30, 2017 and December 31, 2016, we had \$769 million and \$746 million, respectively, of cash, cash equivalents and short and long-term available-for-sale marketable securities. As of September 30, 2017, approximately \$586 million of our cash, cash equivalents and short and long-term marketable securities are held by our subsidiaries outside the United States. Cumulative undistributed earnings of foreign subsidiaries that we intend to indefinitely reinvest outside of the United States totaled approximately \$866 million as of September 30, 2017. Should we distribute, or be treated under certain U.S. tax rules as having distributed, the earnings of foreign subsidiaries in the form of dividends or otherwise, we may be subject to U.S. income taxes. To date, we have permanently reinvested our foreign earnings outside of the United States and we currently do not intend to repatriate these earnings to fund U.S. operations. Determination of the amount of any unrecognized deferred income tax liability on this temporary difference is not practicable because of the complexities of the hypothetical calculation. The majority of cash on hand is denominated in U.S. dollars.

During the nine months ended September 30, 2017, we borrowed an additional \$415 million and repaid \$241 million of outstanding borrowings under the 2015 Credit Facility. These net borrowings during the year were primarily used to repurchase shares of our outstanding common stock under the Company's share repurchase program described below. As of September 30, 2017, we had outstanding borrowings of \$265 million in long-term debt, within our U.S. subsidiaries, and approximately \$932 million of borrowing capacity available under our 2015 Credit Facility, which we are currently borrowing under a one-month interest period, which will reset periodically. The weighted average rate of our outstanding borrowings under the 2015 Credit Facility as of September 30, 2017 was 2.5% per annum. As of September 30, 2017, we were in compliance with the covenants in our 2015 Credit Facility. In addition, we had \$73 million of additional borrowing capacity available under our 2016 Credit Facility. The Company repaid all outstanding borrowings under the 2016 Credit Facility during the three months ended March 31, 2017. Finally, as of September 30, 2017, we had short-term borrowings of \$7 million and approximately \$33 million of available borrowing capacity under our Chinese Credit Facilities, which currently bear interest at a weighted average rate of 4.35%. For further discussion on our credit facilities refer to "Note 6: Debt" in the notes to our unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

In our Vacation Rentals free-to-list model and our Attractions business, we receive cash from travelers at the time of booking and we record these amounts, net of commissions, on our consolidated balance sheets as deferred merchant payables. We pay the suppliers, or the vacation rental owners and tour providers, respectively, after the travelers' use. Therefore, we receive cash from the traveler prior to paying the supplier and this operating cycle represents a working capital source or use of cash to us. Seasonal fluctuations in these transactions affect the timing of our annual cash flows related to working capital. During the first half of the year

vacation rentals and attractions bookings typically exceed stays and tour-taking, resulting in higher cash flow related to working capital, while during the second half of the year, particularly in the third quarter, this pattern reverses and cash flows from these transactions are typically negative. While we expect the impact of seasonal fluctuations to continue, further significant shifts in our business mix or adverse economic conditions could result in future seasonal patterns that are different from historical trends.

On January 25, 2017, our Board of Directors authorized the repurchase of \$250 million of our shares of common stock under a new share repurchase program. As of June 30, 2017, we had repurchased a total of 6,079,003 shares of the Company's outstanding common stock at an average share price of \$41.13, or \$250 million in the aggregate, and completed this share repurchase program.

We believe that our available cash and marketable securities, combined with expected cash flows generated by operating activities and available cash from our credit facilities, will be sufficient to fund our foreseeable working capital requirements, capital expenditures, existing business growth initiatives, debt obligations, lease commitments, and other financial commitments through at least the next twelve months. Our future capital requirements may also include capital needs for acquisitions, share repurchases, and/or other expenditures in support of our business strategy; thus potentially reducing our cash balance and/or increasing our debt. We expect total capital expenditures for 2017 to be comparable to our 2016 spending levels.

Our cash flows from/(used in) in operating, investing and financing activities during the periods presented, as reflected in the unaudited condensed consolidated statements of cash flows, are summarized in the following table:

	Nine months ended September 30, 2017 2016 (in millions)	
Net cash provided by (used in):		
Operating activities	\$220	\$276
Investing activities	64	(140)
Financing activities	(163)	(133)

For the nine months ended September 30, 2017, net cash provided by operating activities decreased by \$56 million or 20% when compared to the same period in 2016, primarily due to a decrease in net income of \$54 million and a net decrease in working capital of \$22 million, partially offset by an increase in non-cash items affecting cash flow of \$20 million. The decrease in working capital movements of \$22 million was primarily due to timing of collection of receivables, income tax payments, and vendor payments, partially offset by an increase in operating cash flow from deferred merchant payables primarily due to growth in our Attractions business.

For the nine months ended September 30, 2017, net cash provided by investing activities increased by \$204 million when compared to the same period in 2016, primarily due to a net increase in cash generated by the purchase, sales, and maturities of our marketable securities of \$175 million, a decrease in cash paid for business acquisitions of \$23 million and a decrease in capital expenditures of \$7 million.

For the nine months ended September 30, 2017, net cash used in financing activities increased by \$30 million when compared to the same period in 2016, primarily due to an increase of \$229 million in cash used in 2017 to purchase shares of our common stock under the authorized share repurchase program, net new borrowings on our 2016 Credit Facility of \$73 million in 2016 which was subsequently repaid in 2017, partially offset by an increase in net borrowings under our 2015 Credit Facility of \$352 million for the first nine months of 2017, when compared to the same period in 2016.

Contractual Obligations, Commercial Commitments and Off-Balance Sheet Arrangements

Since December 31, 2016, there have been no material changes outside the normal course of business to our contractual obligations and commercial commitments. As of September 30, 2017, other than our contractual obligations and commercial commitments, we did not have any off-balance sheet arrangements as defined in Item 303(a)(4)(ii) of Regulation S-K promulgated by the SEC. Refer to “Liquidity and Capital Resources” in Part II, Item 7. —Management’s Discussion and Analysis of Financial Condition and Results of Operations of our Annual Report on Form 10-K for the year ended December 31, 2016 for a discussion of our contractual obligations and commercial commitments.

Contingencies

In the ordinary course of business, we and our subsidiaries are parties to regulatory and legal matters. These matters may relate to claims involving alleged infringement of third-party intellectual property rights, defamation, taxes, regulatory compliance and other claims. Periodically, we review the status of all significant outstanding matters to assess the potential financial exposure. When (i) it is probable that an asset has been impaired or a liability has been incurred, and (ii) the amount of the loss can be reasonably estimated, we record the estimated loss in our consolidated statements of operations. We provide disclosure in the notes to the consolidated statements for loss contingencies that do not meet both of these conditions if there is a reasonable possibility that a loss may have been incurred that would be material to the financial statements. Significant judgment is required to determine the probability that a liability

has been incurred and whether such liability is reasonably estimable. We base accruals made on the best information available at the time which can be highly subjective. Although occasional adverse decisions or settlements may occur, the Company does not believe that the final disposition of any of these matters will have a material adverse effect on the business. However, the final outcome of these matters could vary significantly from our estimates. Moreover, such claims, even if not meritorious, could result in the expenditure of significant financial and managerial resources, divert management's attention from the Company's business objectives and adversely affect the Company's business, results of operations, financial condition and cash flows. There may also be claims or actions pending or threatened against us of which we are currently not aware and the ultimate disposition of which would have a material adverse effect on us.

We are also under audit by the IRS and various other domestic and foreign tax authorities with regards to income tax matters. We have reserved for potential adjustments to our provision for income taxes that may result from examinations by, or any negotiated agreements with, these tax authorities. Although we believe our tax estimates are reasonable, the final determination of audits could be materially different from our historical income tax provisions and accruals. The results of an audit could have a material effect on our financial position, results of operations, or cash flows in the period for which that determination is made.

By virtue of previously filed consolidated income tax returns filed with Expedia, we are currently under an IRS audit for the 2009, 2010, and 2011 tax years, and have various ongoing state income tax audits. We are separately under examination by the IRS for the 2012 and 2013 tax years and under an employment tax audit by the IRS for the 2013 and 2014 tax years. These audits include questioning of the timing and the amount of income and deductions and the allocation of income among various tax jurisdictions. These examinations may lead to proposed or ordinary course adjustments to our taxes. We are no longer subject to tax examinations by tax authorities for years prior to 2009. As of September 30, 2017, no material assessments have resulted, except as noted below regarding our 2009 and 2010 IRS audit with Expedia.

In January 2017, we received Notices of Proposed Adjustment from the IRS for the 2009 and 2010 tax years. These proposed adjustments are related to certain transfer pricing arrangements with our foreign subsidiaries, and would result in an increase to our worldwide income tax expense in an estimated range totaling \$10 million to \$14 million for those specific years, after consideration of competent authority relief, exclusive of interest and penalties. During the quarter ended June 30, 2017, we filed a request for Mutual Agreement Procedure consideration under Article 26 of the United States / United Kingdom Income Tax Convention and Rev. Proc. 2015-40, 2015-35 I.R.B. 236. Our policy is to review and update tax reserves as facts and circumstances change. Based on our interpretation of the regulations and available case law, we believe the position we have taken with regard to transfer pricing with our foreign subsidiaries is sustainable. As such, we disagree with the proposed adjustments and intend to defend our position through applicable administrative and, if necessary, judicial remedies. In addition to the risk of additional tax for 2009 and 2010 transactions, if the IRS were to seek transfer pricing adjustments of a similar nature for transactions in subsequent years, we could be subject to significant additional tax liabilities.

Additionally, we continue to accumulate positive cash flows in foreign jurisdictions, which we consider indefinitely reinvested. Any repatriation of funds currently held in foreign jurisdictions may result in higher effective tax rates and incremental cash tax payments. In addition, there have been proposals to amend U.S. tax laws that would significantly impact the manner in which U.S. companies are taxed on foreign earnings. Although we cannot predict whether or in what form any legislation will pass, if enacted, it could have a material adverse impact on our U.S. tax expense and cash flows.

See "Note 7: Income Taxes" in the notes to our unaudited condensed consolidated financial statements in this Quarterly Report on Form 10-Q for further information on potential contingencies surrounding current audits by the IRS and various other domestic and foreign tax authorities, and other income tax matters.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to certain market risks, including changes in interest rates and foreign currency exchange rates that could adversely affect our results of operations or financial condition. Our exposure to market risk includes our revolving credit facilities, derivative instruments and cash and cash equivalents, short term and long term marketable securities, accounts receivable, intercompany balances, accounts payable and deferred merchant payables denominated in foreign currencies. We manage our exposure to these risks through established policies and procedures and by assessing the anticipated near-term and long-term fluctuations in interest rates and foreign currency exchange rates. Our objective is to mitigate potential income statement, cash flow and market exposures from changes in foreign currency exchange rates and interest rates.

There has been no material change in our market risk profile during the nine months ended September 30, 2017. For additional information, see “Quantitative and Qualitative Disclosures About Market Risk” in Item 7A. in Part II of our Annual Report on Form 10-K for the year ended December 31, 2016.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of September 30, 2017, our management, with the participation of our President and Chief Executive Officer and our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15(b) promulgated under the Securities Exchange Act of 1934, as amended, or the Exchange Act. Based upon that evaluation, our President and Chief Executive Officer and our Chief Financial Officer concluded that, as of September 30, 2017, our disclosure controls and procedures were effective in ensuring that material information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, including ensuring that such material information is accumulated and communicated to our management, including our President and Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes to our internal control over financial reporting that occurred during the quarter ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

In the ordinary course of business, we are parties to legal proceedings and claims involving alleged infringement of third-party intellectual property rights, defamation, taxes, regulatory compliance and other claims. Rules and regulations promulgated by the SEC require the description of material pending legal proceedings, other than ordinary, routine litigation incident to the registrant's business, and advise that proceedings ordinarily need not be described if they primarily involve damages claims for amounts (exclusive of interest and costs) not individually exceeding 10% of the current assets of the registrant and its subsidiaries on a consolidated basis. In the judgment of management, none of the pending litigation matters that we are defending involves or is likely to involve amounts of that magnitude. Such matters, however, even if not meritorious, could result in the expenditure of significant financial and managerial resources, divert management's attention from the Company's business objectives and adversely affect the Company's business, results of operations, financial condition and cash flows. In addition, there may be claims or actions pending or threatened against us of which we are currently not aware and the ultimate disposition of which could have a material adverse effect on us.

Item 1A. Risk Factors

You should consider carefully the risks described below together with all of the other information included in this Quarterly Report as they may impact our business, results of operations and/or financial condition. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties not presently known to us or that we currently believe are immaterial may also impair our business, results of operations or financial condition. If any of the following risks occur, our business, financial condition, operating results and cash flows could be materially adversely affected.

If we are unable to continue to increase visitors to our websites and mobile apps and to cost-effectively convert these visitors into revenue-generating users, our revenue, financial results and business could be harmed.

Our long term success depends on our continued ability to maintain and increase the overall number of visitors flowing through our platforms in a cost effective manner, to engage users throughout the travel planning and booking phases and to attract consumers who will share their reviews from their trips. The primary asset that we use to attract visitors to our websites and convert these visitors into engaged users and bookers is our ability to collect or create, organize and distribute high-quality, commercially valuable content and products that meet users' specific interests. Our traffic and user engagement could be adversely affected by a number of factors, including but not limited to increased competition, reduced consumer awareness of our brands, declines or inefficiencies in traffic acquisition, and macroeconomic conditions. Certain of our competitors have advertising campaigns expressly designed to drive consumer traffic directly to their websites, and these campaigns may negatively impact traffic to our site. There can be no assurances that we will continue to provide content and products in a cost-effective manner, in a manner that meets rapidly changing consumer demand and in a manner that encourages users to book on our platform. Any failure to obtain and manage content and products in a cost-effective manner that will engage users, or any failure to provide content and products that are perceived as useful, reliable and trustworthy, could adversely affect user experiences and their repeat behavior, reduce traffic to our websites and negatively impact our business and financial performance.

Our dedication to making the user experience our highest priority may cause us to prioritize rapid innovation and user experience over short-term financial results.

We strive to create the best experience for our users, providing them with the information, research and tools to enable them to plan, book, and experience the perfect trip. We believe that in doing so we will increase our rates of conversion, revenue per shopper and, ultimately, our financial performance over the long-term. We have taken actions in the past and may continue to make decisions in the future that have the effect of reducing our short-term revenue or profitability if we believe that the decisions benefit the aggregate user experience. For example, we may introduce changes to existing products or new products that direct users away from formats or use cases where we have a proven means of monetization. In addition, our approach of putting users first may negatively impact our relationship with existing or prospective advertisers. These actions and practices could result in a loss of advertisers, which in turn could harm our results of operations. The short-term reductions in revenue or profitability could be more severe than we anticipate or these decisions may not produce the long-term benefits that we expect, in which case our user growth and engagement, our relationships with users and advertisers, and our business and results of operations could be harmed.

We derive a substantial portion of our revenue from advertising and any significant reduction in spending by advertisers or redirections of advertising spend could harm our business.

We derive a substantial portion of our revenue from the sale of advertising, primarily through click-based advertising and, to a lesser extent, display-based advertising. We enter into master advertising contracts with our advertising partners, however, the agreement terms are generally limited to matters such as privacy and compliance, payment terms and conditions, termination and indemnities and most of these contracts can be terminated by our partners at will or on short notice. Our ability to grow advertising revenue with our existing or new advertising partners is dependent in large part on our ability to generate revenue for them relative to other alternatives. Advertisers will not continue to do business with us if their investment in such advertising does not generate sales leads, customers, bookings, or revenue and profit on a cost-effective basis. Our ability to provide value to our advertising partners depends on a number of factors, including acceptance of online advertising versus more traditional forms of advertising or more effective models, competitiveness of our products, traffic quality, perception of our platform, availability and accuracy of analytics and measurement solutions to demonstrate our value, and macroeconomic conditions, whether in the advertising industry generally, among specific types of marketers or within particular geographies. We cannot guarantee that our current advertisers will fulfill their obligations under existing contracts, continue to advertise beyond the terms of existing contracts or enter into any additional contracts with us.

Click-based advertising revenue accounts for the majority of our advertising revenue. Our CPC pricing for click-based advertising depends, in part, on competition between advertisers. If our large advertisers become less competitive with each other, merge with each other or with our competitors, focus more on per-click profit than on traffic volume, or are able to reduce CPCs, this could have an adverse impact on our click-based advertising revenue which would, in turn, have an adverse effect on our business, financial condition and results of operations.

We rely on a relatively small number of significant advertising partners and any reduction in spending by or loss of these partners could seriously harm our business.

We derive a substantial portion of our revenue from a relatively small number of advertising partners and rely significantly on our relationships. For example, for the year ended December 31, 2016, our two most significant advertising partners, Expedia and Priceline (and their subsidiaries), accounted for a combined 46% of total revenue. While we enter into master advertising contracts with our partners, the terms of these agreements generally address matters such as privacy and compliance, payment terms and conditions, termination and indemnities and most of these contracts can be terminated by our partners at will or on short notice. If any of our significant advertisers were to cease

or significantly curtail advertising on our websites, we could experience a rapid decline in our revenue over a relatively short period of time which would have a material impact on our business.

Changes in internet search engine algorithms and dynamics, or search engine disintermediation, could have a negative impact on traffic for our sites and, ultimately, our business and results of operations.

We rely heavily on internet search engines, such as Google, to generate traffic to our websites, principally through the purchase of travel-related keywords as well as through free, or organic, search. Pricing and operating dynamics for these traffic sources can change rapidly, both technically and competitively. Search engines frequently update and change the logic that determines the placement and display of results of a user's search, such that the purchased or algorithmic placement of links to our websites can be negatively affected. In addition, a search engine could, for competitive or other purposes, alter its search algorithms or results causing our websites to place lower in organic search query results. If a major search engine changes its algorithms in a manner that negatively affects the search engine ranking of our websites or those of our partners, or if competitive dynamics impact the cost or effectiveness

of SEO or SEM in a negative manner, our business and financial performance would be adversely affected. Furthermore, our failure to successfully manage our SEO and SEM strategies could result in a substantial decrease in traffic to our websites, as well as increased costs if we were to replace free traffic with paid traffic.

In addition, to the extent that Google or other leading search or metasearch engines that have a significant presence in our key markets, disintermediate OTAs or travel content providers, whether by offering their own comprehensive travel planning or shopping capabilities, or by referring leads to suppliers, other favored partners or themselves directly, there could be a material adverse impact on our business and financial performance. To the extent these actions have a negative effect on search results and traffic to our site, our business and financial performance could be adversely affected.

We also rely on application marketplaces, such as Apple's App Store and Google's Play, to drive downloads of our applications. In the future, Apple, Google or other marketplace operators may make changes to their marketplaces that make access to our products more difficult. For example, our applications may receive unfavorable treatment compared to the promotion and placement of competing applications, such as the order in which they appear within marketplaces. Similarly, if problems arise in our relationships with providers of application marketplaces, traffic to our site and our user growth could be harmed.

We continue to invest significant time and effort towards educating users about our brand and our product offerings and there can be no assurances that these efforts will be successful.

The markets for the services we offer are intensely competitive, and some of our current and potential competitors have access to significantly greater and more diversified resources than we do, and they may be able to leverage other aspects of their businesses to enable them to compete more effectively with us. In an effort to be more competitive, we engage in marketing efforts aimed at increasing awareness of our ability to find our users the right hotels at the lowest prices. Specifically, we initiated a television advertising campaign and reallocated some of our marketing efforts and dollars among the different marketing channels available to us. We expect to continue our television advertising campaign and to adjust our marketing efforts and spend among the different marketing channels, in each case as we think appropriate based on the relative growth opportunity, the expected returns and the competitive environment in the different segments and businesses in which we operate. There is no assurance that these actions will have a positive impact on our marketing efficiencies and/or operating margins or when the financial benefit expected to results from these efforts will exceed the costs of such efforts.

Consumer adoption and use of mobile phone devices creates new challenges and, if we are unable to operate effectively on mobile phone devices, our business may be adversely affected.

The number of people who access the internet through mobile phones has increased substantially in the last few years and we anticipate that the rate of use of these devices will continue to grow. The mobile phone market in general remains a rapidly evolving market and mobile phones continue to monetize at a significantly lower rate than desktops and tablets. Advertising opportunities may be more limited on mobile phone devices. Given the device sizes and technical limitations of these devices, mobile phone consumers may not be willing to download multiple apps from multiple companies providing similar service and instead prefer to use one or a limited number of apps for their hotel, restaurant and attractions activity. In addition, as new devices and platforms are released, users may begin consuming content in a manner that is more difficult to monetize.

To address these growing user demands, we continue to extend our platform to develop and improve upon our mobile applications and monetization strategies. If we are unable to continue to rapidly innovate and create new, user-friendly

and differentiated mobile phone offerings and websites optimized for mobile phone devices and efficiently and effectively advertise and distribute on these platforms, or if our mobile phone offerings are not used by consumers, our future growth and results of operations could be negatively impacted.

Declines or disruptions in the economy in general and travel industry in particular could adversely affect our businesses and financial performance.

Our businesses and financial performance are affected by the health of the global economy generally as well as the travel industry and leisure travel in particular. Sales of travel services tend to decline or grow more slowly during economic downturns and recessions when consumers engage in less discretionary spending, are concerned about unemployment or economic weakness, have reduced access to credit or experience other concerns that reduce their ability or willingness to travel. The global economy may be adversely impacted by unforeseen events beyond our control including incidents of actual or threatened terrorism, regional hostilities or instability, unusual weather patterns, natural disasters, political instability and health concerns (including epidemics or pandemics), defaults on government debt, significant increases in fuel and energy costs, tax increases and other matters that could reduce discretionary spending, tightening of credit markets and further declines in consumer confidence. Decreased travel expenditures could reduce the demand for our services and have a negative impact on our business, working capital and financial performance.

In addition, the uncertainty of macro-economic factors and their impact on consumer behavior, which may differ across regions, makes it more difficult to forecast industry and consumer trends and the timing and degree of their impact on our markets and business, which in turn could adversely affect our ability to effectively manage our business and adversely affect our results of operations.

On June 23, 2016, the United Kingdom held a referendum in which a majority of voters voted to exit the European Union (“Brexit”). Since the referendum, global markets and foreign currency exchange rates have experienced increased volatility. To leave the European Union, the United Kingdom must negotiate the terms of its exit and the process could take two years or more. Brexit could adversely affect European and global economic or market conditions and could contribute to instability in global financial markets, although the effects of Brexit are not yet known and will depend upon, among other things, the terms, nature and timing of the exit. Any of these effects of Brexit, and others we cannot anticipate, may have a negative effect on the travel industry and may adversely affect our business.

We rely on the value of our brands and consumer trust in our brands. If we are not able to protect, maintain and enhance our brands, or if events occur that damage our reputation and brands, our business may be harmed.

We believe that the strength of our brands (particularly the TripAdvisor brand) has contributed significantly to our success and that maintaining and enhancing our brands is critical to expanding our base of users, creating content and attracting advertisers. As a result, we invest significantly in brand marketing. We expect these investments to continue, and even increase, as a result of a variety of factors, including relatively high levels of advertising spending from competitors, the increasing costs of supporting multiple brands, expansion into new geographies, product positioning where our brands are less well known, inflation in media pricing, and the continued emergence and relative traffic share growth of search engines as destination sites for travelers. Such efforts may not maintain or enhance consumer awareness of our brands and, even if we are successful in our branding efforts, such efforts may not be cost-effective or as efficient as they have been historically. If we are unable to maintain or enhance consumer awareness of our brands or to generate demand in a cost-effective manner, it would have a material adverse effect on our business and financial performance.

Our ability to protect, maintain and enhance our brands also depends largely on our ability to maintain consumer confidence in our products and in the quality and integrity of our content and other information found on our platform. If consumers do not believe our recommended reviews to be useful and reliable, they may seek other services to obtain the information for which they are looking and may not return to our platform as often in the future, or at all. In addition, unfavorable publicity regarding, for example, our practices relating to privacy and data protection, product changes, competitive pressures, reviews and content, litigation or regulatory activity, could adversely affect our reputation with our users and our advertisers. Such negative publicity also could have an adverse effect on the size, engagement, and loyalty of our user base and result in decreased revenue, which could adversely affect our business and financial results.

We operate in an increasingly competitive global environment and our failure to compete effectively could reduce our market share and harm our financial performance.

We compete in rapidly evolving and competitive markets. We face competition for content, users, advertisers, online travel search and price comparison services, or what is known in the industry as hotel metasearch, and online reservations. In the competition to attract users to our platform, we rely on our ability to acquire traffic through offline brand recognition and brand-direct efforts such as online search, email and television. These marketing strategies can be impacted by competitive site content, changes to our website architecture and page designs, changes to search engine ranking algorithms, updates in competitor advertising strategies, or changes to display ordering in search engine results such as preferred placement for internal products offered by search engines.

We also compete with different types of companies in the various markets and geographies we participate in, including large and small companies in the travel space as well as broader service providers. More specifically:

In our Hotel segment, we face competition from OTAs (including Expedia, Inc. and The Priceline Group Inc. and certain of their respective subsidiaries), hotel metasearch providers (including Trivago, Kayak, Ctrip.com International, Ltd., and HotelsCombined), large online search, social media, and marketplace companies (including Google, Microsoft Bing, Yahoo, Baidu, Facebook, Alibaba, and Amazon), traditional offline travel agencies, and global hotel chains seeking to promote direct bookings.

We also face competition from different companies in each of the operating segments in our Non-Hotel segment. Our Attractions business competes with traditional travel agencies, wholesalers, and individual tour operators as well as Airbnb and similar websites that have added other travel services such as tours and activities. Our Restaurants business competes with other online restaurant reservation services, such as SeatMe (owned by Yelp) and OpenTable

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subsidiary of Priceline). Our Vacation Rentals business competes with companies focused on alternative lodging, shared accommodations and online accommodation searches, including Airbnb, HomeAway (a subsidiary of Expedia) and booking.com (a subsidiary of Priceline).

Many of our competitors have significantly greater financial, technical, marketing and other resources compared to us and have expertise in developing online commerce and facilitating internet traffic as well as large client bases. They also have the ability to leverage other aspects of their business to enable them to compete more effectively against us. In addition, many of our competitors, including online search companies, continue to expand their voice and artificial intelligence capabilities, which may provide them with a competitive advantage in travel. We cannot assure you that we will be able to compete successfully against our current, emerging and future competitors or on platforms that may emerge, or provide differentiated products and services to our traveler base.

Certain of the companies we do business with, including some of our click-based advertising partners, are also our competitors. The consolidation of our competitors and partners, including Expedia (through its acquisitions of Orbitz, Travelocity, and HomeAway) and Priceline (through its acquisitions of Kayak and OpenTable), may affect our relative competitiveness and our partner relationships. Competition and consolidation could result in higher traffic acquisition costs, reduced margins on our advertising services, loss of market share, reduced customer traffic to our websites and reduced advertising by travel companies on our websites.

As the industry shifts towards online travel services and the technology supporting it continues to evolve, including platforms such as mobile phone and tablet computing devices, competition is likely to intensify. Competition in our industry may result in pricing pressure, loss of market share or decreased member engagement, any of which could adversely affect our business and financial performance.

We rely on information technology to operate our business and remain competitive, and any failure to adapt to technological developments or industry trends could harm our businesses.

We depend on the use of sophisticated information technologies and systems for, among other things, website and mobile apps, supplier connectivity, communications, reservations, payment processing, procurement, customer service and fraud prevention. Our future success depends on our ability to continuously improve and upgrade our systems and infrastructure to meet rapidly evolving consumer trends and demands while at the same time maintaining the reliability and integrity of our systems and infrastructure. We may not be able to maintain or replace our existing systems or introduce new technologies and systems as quickly as we would like or in a cost-effective manner. We may not be successful, or as successful as our competitors, in developing technologies and systems that operate effectively across multiple devices and platforms in a way that is appealing to our users.

In addition, the emergence of alternative platforms such as mobile phone and tablet computing devices and the emergence of niche competitors who may be able to optimize products, services or strategies for such platforms will require new investment in technology. New developments in other areas, such as cloud computing, could also make it easier for competition to enter our markets due to lower up-front technology costs.

If we do not continue to innovate and provide tools and services that are useful to travelers, we may not remain competitive, and our business and financial performance could suffer.

Our success depends in part on continued innovation to provide features and services that make our platform compelling to travelers. Our competitors are continually developing innovations in online travel-related services and features. As a result, we are continually working to improve our business model and user experience in order to drive user traffic and conversion rates. We can give no assurances that the changes we make will yield the benefits we expect and will not have unintended or adverse impacts that we did not anticipate. If we are unable to continue offering innovative products and services and quality features that travelers want to use, existing users may become

dissatisfied and use competitors' offerings and we may be unable to attract additional users, which could adversely affect our business and financial performance.

We are dependent upon the quality of traffic in our network to provide value to online advertisers, and any failure in our quality control could have a material adverse effect on the value of our websites to our advertisers and adversely affect our revenue.

We use technology and processes to monitor the quality of the internet traffic that we deliver to online advertisers and have identified metrics to demonstrate the quality of that traffic. These metrics are used to not only identify the value of advertising on our website but also to identify low quality clicks such as non-human processes, including robots, spiders or other software; the mechanical automation of clicking; and other types of invalid clicks or click fraud. Even with such monitoring in place, there is a risk that a certain amount of low-quality traffic, or traffic that online advertisers deem to be invalid, will be delivered to such online

advertisers. As a result, we may be required to credit amounts owed to us by our advertisers. Furthermore, low-quality or invalid traffic may be detrimental to our relationships with advertisers, and could adversely affect our advertising pricing and revenue.

We rely on assumptions and estimates and data to calculate certain of our key metrics, and real or perceived inaccuracies in such metrics may harm our reputation and negatively affect our business.

We believe that certain metrics are key to our business, including but not limited to unique visitors, hotel shoppers, revenue per hotel shopper, and number of reviews and opinions. As the industry in which we operate and our business continues to evolve, so too might the metrics by which we evaluate our business. While the calculation of these metrics is based on what we believe to be reasonable estimates, our internal tools are not independently verified by a third party and have a number of limitations and, furthermore, our methodologies for tracking these metrics may change over time. For example, a single person may have multiple accounts or browse the internet on multiple browsers or devices, some users may restrict our ability to accurately identify them across visits, some mobile applications automatically contact our servers for regular updates with no user action, and we are not always able to capture user information on all of our platforms. As such, the calculations of our unique visitors may not accurately reflect the number of people actually visiting our platforms. We continue to improve upon our tools and methodologies to capture data and believe that our current metrics are more accurate; however, the improvement of our tools and methodologies could cause inconsistency between current data and previously reported data, which could confuse investors or lead to questions about the integrity of our data. Also if the internal tools we use to track these metrics under-count or over-count performance or contain algorithm or other technical errors, the data we report may not be accurate. In addition, historically, certain metrics were calculated by independent third parties. Accordingly readers should not place undue reliance on these numbers.

The loss of one or more of our key personnel, or our failure to attract and retain other highly qualified personnel in the future, could harm our business.

Our future success depends upon the continued contributions of our senior corporate management and other key employees. In particular, the contributions of Stephen Kaufer, our co-founder, President and Chief Executive Officer, are critical to our overall management. We cannot ensure that we will be able to retain the services of these individuals, and the loss of one or more of our key personnel could seriously harm our business. We do not maintain any key person life insurance policies.

In addition, competition remains intense for well-qualified employees in certain aspects of our business, including software engineers, developers, product management and development personnel, and other technology professionals. Our continued ability to compete effectively depends on our ability to attract new employees and to retain and motivate existing employees. As a global company, we aim to attract quality employees from all over the world, so any restrictions on travel for professional or personal purposes, such as those put in place in the United States in early 2017, may cause significant disruption to our businesses or negatively affect our ability to attract and retain employees on a global basis. If we do not succeed in attracting well-qualified employees or retaining or motivating existing employees, our business would be adversely affected.

The online vacation rental market is rapidly evolving and if we fail to predict the manner in which the market develops, our business and prospects may suffer.

We offer vacation rental services on our TripAdvisor-branded sites as well as through our U.S.-based FlipKey and Vacation Home Rentals and European-based Holiday Lettings and Niumba businesses. The vacation rental market has been and continues to be, subject to regulatory development that affects the vacation rental industry and the ability of companies like us to list those vacation rentals online. For example, some states and local jurisdictions have adopted

or are considering statutes or ordinances that prohibit property owners and managers from renting certain properties for fewer than 30 consecutive days or otherwise limit their ability to do so, and other states and local jurisdictions may introduce similar regulations. Some states and local jurisdictions also have fair housing or other laws governing whether and how properties may be rented, which they assert apply to vacation rentals. Many homeowners, condominium and neighborhood associations have adopted rules that prohibit or restrict short-term vacation rentals. Many of the fundamental statutes and ordinances that impose taxes or other obligations on travel and lodging companies were established before the growth of the internet and e-commerce, which creates a risk of these laws being used in ways not originally intended that could burden property owners and managers or otherwise harm our business. Operating in this dynamic regulatory environment requires significant management attention and financial resources. We cannot assure that our efforts will be successful, and the investment and additional resources required to manage growth will produce the desired levels of revenue or profitability.

We may be subject to claims that we violated intellectual property rights of others and these claims can be extremely costly to defend and could require us to pay significant damages and limit our ability to operate.

Certain companies in the internet and technology industries that own patents, copyrights, trademarks and trade secrets frequently enter into litigation based on allegations of infringement or other violations of those intellectual property rights in order to extract value from technology companies, such as royalties in connection with grants of licenses. We have received in the past, and expect in the future to receive notices that claim we have misappropriated or misused other parties' intellectual property rights. Any intellectual property claim against us, regardless of merit, could be time-consuming and expensive to settle or litigate and could divert management's attention and other resources. These claims also could subject us to significant liability for damages and could result in our having to stop using technology or content found to be in violation of another party's rights. We might be required or may opt to seek a license for rights to intellectual property held by others, which may not be available on commercially reasonable terms, or at all. Even if a license is available, we could be required to pay significant royalties, which would increase our operating expenses. We may also be required to develop alternative non-infringing technology, or content, which could require significant effort and expense and make us less competitive in the relevant market. Any of these results could harm our business and financial performance.

Acquisitions, investments, significant commercial arrangements and/or new business strategies could disrupt our ongoing business and present new challenges and risks.

Our success will depend, in part, on our ability to expand our product offerings and expand user engagement in order to grow our business in response to changing technologies, user and advertiser demands and competitive pressures. As a result, we have acquired, invested in and/or entered into significant commercial arrangements with a number of new business in the past and our future growth may depend, in part, on future acquisitions, investments, commercial arrangements/or changes in business strategies, any of which could be material to our financial conditions and results of operations. Such endeavors may involve significant risks and uncertainties, including, but not limited to, the following:

- Expected and unexpected costs incurred in identifying and pursuing these endeavors, and performing due diligence on potential targets that may or may not be successful;
- Use of cash resources and incurrence of debt and contingent liabilities in funding these endeavors that may limit other potential uses of our cash, including stock repurchases, retirement of outstanding indebtedness and/or dividend payments;
- Amortization expenses related to acquired intangible assets and other adverse accounting consequences;
 - Diversion of management's attention or other resources from our existing business;
- Difficulties and expenses in integrating the operations, products, technology, privacy protection systems, information systems or personnel of the company, including the assimilation of corporate cultures;
- Difficulties in implementing and retaining uniform standards, controls, procedures, policies and information systems;
- The assumption of known and unknown debt and liabilities of the acquired company, including costs associated with litigation and other claims relating to the acquired company;
- Failure of any company which we have acquired, in which we have invested, or with which we have a commercial arrangement, to achieve anticipated revenues, earnings or cash flows or to retain key management or employees;
- Failure to generate adequate returns on acquisitions and investments;
- With respect to minority investments, limited management or operational control and reputational risk, which risk is heightened if the controlling person in such case has business interests, strategies or goals that are inconsistent with ours;
- Entrance into markets in which we have no direct prior experience and increased complexity in our business;
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Impairment of goodwill or other intangible assets such as trademarks or other intellectual property arising from acquisitions; and

• Adverse market reaction to acquisitions.

We have recently invested, and may in the future invest, in privately-held companies and these investments are currently accounted for under the cost method. Such investments are inherently risky in that such companies are typically at an early stage of development, may have no or limited revenues, may not be or may never become profitable, may not be able to secure additional funding or their technologies, services or products may not be successfully developed or introduced into the market. Further, our ability to liquidate any such investments is typically dependent upon some liquidity event, such as a public offering or acquisition, since no public market exists for such securities. Valuations of such privately-held companies are inherently complex and uncertain

due to the lack of liquid market for the company's securities. Moreover, we could lose the full amount of any of our investments and any impairment of our investments could have a material adverse effect on our financial condition and results of operations.

We cannot assure you that these investments will be successful or that such endeavors will result in the realization of the full benefits of synergies, cost savings, innovation and operational efficiencies that may be possible or that we will achieve these benefits within a reasonable period of time.

If we fail to manage our growth effectively, our brand, results of operations and business could be harmed.

We have experienced rapid growth in our headcount and operations, including through acquisitions of other businesses and in new international markets. We continue to make substantial investments in our technology and sales and marketing organizations. This growth places substantial demands on management and our operational infrastructure. In addition, as our business matures, we make periodic changes and adjustments to our organization in response to various internal and external considerations, including market opportunities, the competitive landscape, new and enhanced products and acquisitions. These changes may result in a temporary lack of focus or productivity or otherwise impact our business.

To manage our growth, we may need to improve our operational, financial and management systems and processes which may require significant capital expenditures and allocation of valuable management and employee resources. As we continue to grow, we must effectively integrate, develop and motivate a large number of new employees, including employees in international markets, while maintaining the beneficial aspects of our company culture. If we do not manage the growth of our business and operations effectively, the quality of our platform and efficiency of our operations could suffer, which could harm our brand, results of operations and business.

We are regularly subject to claims, suits, government investigations, and other proceedings that may result in adverse outcomes.

We are regularly subject to claims, suits, government investigations and other proceedings involving competition, intellectual property, privacy and data protection, consumer protection, tax, labor and employment, commercial disputes, content generated by our users, free speech issues, goods and services offered by advertisers or publishers using our platforms, and other matters. In addition, our businesses face intellectual property litigation that exposes us to the risk of exclusion and cease and desist orders, which could limit our ability to sell products and services.

Such claims, suits, government investigations and proceedings are inherently uncertain and their results cannot be predicted with certainty. Regardless of the outcome, any of these types of legal proceedings can have an adverse impact on us because of legal costs, diversion of management resources, injunctions or damage awards and other factors. Determining reserves for our pending litigation or other legal proceedings is a complex, fact-intensive process that requires significant judgment. It is possible that a resolution of one or more such proceedings could result in substantial fines and penalties that could adversely affect our business, consolidated financial position, results of operations, or cash flows in a particular period. These proceedings could also result in reputational harm, criminal sanctions, consent decrees, or orders preventing us from offering certain features, functionalities, products, or services, requiring a change in our business practices or other field action, or requiring development of non-infringing or otherwise altered products or technologies. Any of these consequences could adversely affect our business and results of operations.

We are a global company that operates in many different jurisdictions and these operations expose us to additional risks, which risks increase as our business continues to expand.

We operate in a number of jurisdictions both inside and outside of the United States and continue to expand our operations both domestically and internationally. Many regions have different economic conditions, languages, currencies, consumer expectations, levels of consumer acceptance and use of the internet for commerce, legislation, regulatory environments (including labors laws and customs), tax laws and levels of political stability. We are subject to associated risks typical of global businesses, including, but not limited to, the following:

- Compliance with additional laws, including the Foreign Corrupt Practices Act and U.K. Bribery Act, data privacy requirements, labor and employment law, laws regarding advertisements and promotions and anti-competition regulations;
- Diminished ability to legally enforce contractual rights;
- Increased risk and limits on enforceability of intellectual property rights;
- Restrictions on repatriation of cash as well as restrictions on investments in operations in certain countries;
- Financial risk arising from transactions in multiple currencies as well as foreign currency exchange restrictions;

- Slower adoption of the internet as an advertising, broadcast and commerce medium in certain international markets;
- Difficulties in managing staff and operations due to distance, time zones, language and cultural differences;
- Uncertainty regarding liability for services, content and intellectual property rights, including uncertainty as a result of local laws and lack of precedent;
- Economic or political instability; and
- Threatened or actual acts of terrorism.

For example, we have a business operating in China, which creates particular risks and uncertainties relating to the laws in China. The laws and regulations of China restrict foreign investment in areas including air-ticketing and travel agency services, internet content provision, mobile communication and related businesses. Although we have established effective control of our Chinese business through a series of agreements, future developments in the interpretation or enforcement of Chinese laws and regulations or a dispute relating to these agreements could restrict our ability to operate or restructure this business or to engage in strategic transactions. The success of this business, and of any future investments in China, is subject to risks and uncertainties regarding the application, development and interpretation of China's laws and regulations.

Additionally, we continue to accumulate positive cash flows in foreign jurisdictions, which we consider indefinitely reinvested. The repatriation of such funds for use in the United States, including for corporate purposes such as acquisitions, stock repurchases, dividends or debt refinancings, may result in additional U.S. income tax expense and higher cost for such capital.

A failure to comply with current laws, rules and regulations or changes to such laws, rules and regulations and other legal uncertainties may adversely affect our business or financial performance.

Our business and financial performance could be adversely affected by unfavorable changes in or interpretations of existing laws, rules and regulations or the promulgation of new laws, rules and regulations applicable to us and our business, including those relating to the internet and online commerce, internet advertising, consumer protection, data security and privacy, travel and vacation rental licensing and listing requirements and tax. In some cases, these laws continue to evolve.

For example, there is, and will likely continue to be, an increasing number of laws and regulations pertaining to the internet and online commerce that may relate to liability for information retrieved from or transmitted over the internet, online editorial and user-generated content, user privacy, data security, behavioral targeting and online advertising, taxation, liability for third-party activities and the quality of products and services. In addition, enforcement authorities continue to rely on their authority under existing consumer protection laws to take action against companies relating to data privacy and security practices. The growth and development of online commerce may prompt calls for more stringent consumer protection laws and more aggressive enforcement efforts, which may impose additional burdens on online businesses generally.

Further, our Vacation Rentals business has been and continues to be subject to regulatory developments that affect the vacation rental industry and the ability of competitors like us to list those vacation rentals online. For example, some states and local jurisdictions have adopted or are considering adopting statutes or ordinances that prohibit property owners and managers from renting certain properties for fewer than 30 consecutive days. Some states and local jurisdictions also have fair housing or other laws governing whether and how properties may be rented, which they

assert apply to vacation rentals. Many homeowners, condominium and neighborhood associations have adopted rules that prohibit or restrict short-term vacation rentals.

We also have been subject, and we will likely be subject in the future, to inquiries from time to time from regulatory bodies concerning compliance with consumer protection, competition, tax and travel industry-specific laws and regulations. The failure of our businesses to comply with these laws and regulations could result in fines and/or proceedings against us by governmental agencies and/or consumers, which if material, could adversely affect our business, financial condition and results of operations. Further, if such laws and regulations are not enforced equally against other competitors in a particular market, our compliance with such laws may put us a competitive disadvantage vis-à-vis competitors who do not comply with such requirements.

The promulgation of new laws, rules and regulations, or the new interpretation of existing laws, rules and regulations, in each case that restrict or otherwise unfavorably impact the ability or manner in which we provide services could require us to change certain aspects of our business, operations and commercial relationships to ensure compliance, which could decrease demand for services, reduce revenues, increase costs and/or subject the company to additional liabilities. Unfavorable changes could decrease demand for products and services, limit marketing methods and capabilities, increase costs and/or subject us to additional liabilities. Violations of these laws and regulations could result in finds and/or criminal sanctions against us, our officers or our employees and/or prohibitions on the conduct of our business.

We cannot be sure that our intellectual property is protected from copying or use by others, including potential competitors.

Our websites rely on content, brands and technology, much of which is proprietary. We protect our proprietary content, brands and technology by relying on a combination of trademarks, copyrights, trade secrets, patents and confidentiality agreements. Any misappropriation or violation of our rights could have a material adverse effect on our business. Even with these precautions, it may be possible for another party to copy or otherwise obtain and use our proprietary technology, content or brands without authorization or to develop similar technology, content or brands independently.

Effective intellectual property protection is expensive to develop and maintain, both in terms of initial and ongoing registration requirements and expenses and the costs of defending our rights. In addition, effective intellectual property protection may not be available in every jurisdiction in which our services are made available, and policing unauthorized use of our intellectual property is difficult and expensive. Therefore, in certain jurisdictions, we may be unable to protect our intellectual property adequately against unauthorized third-party copying or use, which could adversely affect our business or ability to compete. We cannot be sure that the steps we have taken will prevent misappropriation or infringement of our intellectual property. Furthermore, we may need to go to court or other tribunals or administrative bodies in order to enforce our intellectual property rights, to protect our trade secrets or to determine the validity and scope of the proprietary rights of others. These proceedings might result in substantial costs and diversion of resources and management attention. Our failure to protect our intellectual property in a cost-effective or effective manner could have a material adverse effect on our business and ability to protect our technology, content and brands.

We currently license from third parties and incorporate the technologies and content into our websites. As we continue to introduce new services that incorporate new technologies and content, we may be required to license additional technology, or content. We cannot be sure that such technology or content will be available on commercially reasonable terms, if at all.

Our processing, storage and use of personal information and other data exposes us to risks of external and internal security breaches and could give rise to liabilities.

We are subject to a variety of laws in the United States and abroad regarding privacy and the storing, sharing, use, processing, disclosure and protection of personal information and other consumer data, the scope of which are changing, subject to differing interpretations, and may be inconsistent between countries or conflict with other rules. In addition, the security of data when engaging in electronic commerce is essential to maintaining consumer and travel service provider confidences in our services. The regulatory framework for privacy issues worldwide is currently in flux and is likely to remain so for the foreseeable future. Practices regarding the collection, use, storage, transmission and security of personal information by companies operating over the internet have recently come under increased public scrutiny. The U.S. Congress and federal agencies, including the Federal Trade Commission and the Department of Commerce, are reviewing the need for greater regulation for the collection and use of information concerning consumer behavior on the internet. Various U.S. courts are also considering the applicability of existing federal and state statutes, including computer trespass and wiretapping laws, to the collection and exchange of information online. In addition, the European Union has adopted a new data protection legal framework, effective in May 2018, which may result in a greater compliance burden for companies, including us, with users in Europe and increased costs of compliance.

Potential security breaches to our systems, whether resulting from internal or external sources, could significantly harm our business. A party, whether internal or external, that is able to circumvent our security systems could misappropriate user information or proprietary information or cause significant interruptions in our operations. In the

past, we have experienced “denial-of-service” type attacks on our systems that have made portions of our websites unavailable for short periods of time as well as allowed unauthorized access of our systems and data. We also face risks associated with security breaches affecting third parties conducting business over the internet. Much of our business is conducted with third party marketing affiliates or, more recently, through business partners powering our instant booking feature. In addition, we frequently use third parties to process credit card payments. A security breach at such third party could be perceived by consumers as a security breach of our systems and could result in negative publicity, damage our reputation, expose us to risk of loss or litigation and possible liability and subject us to regulatory penalties and sanctions. In addition, such third parties may not comply with applicable disclosure requirements, which could expose us to liability.

We strive to comply with all applicable laws, policies, legal obligations and industry codes of conduct relating to privacy and data protection. Any failure or perceived failure by us to comply with our privacy policies, privacy-related obligations to users or other third parties, or privacy-related legal obligations, or any compromise of security that results in the unauthorized release or transfer of personally identifiable information or other user data, may result in governmental enforcement actions, litigation or public statements that could harm our reputation and cause our customers and members to lose trust in us, which could have an adverse effect on our business, brand, market share and results of operations. We may need to expend significant resources to protect against security breaches or to investigate and address problems caused by breaches. Reductions in website availability could cause a loss of substantial business volume during the occurrence of any such incident. Because the techniques used to sabotage security change frequently, often are not recognized until launched against a target and may originate from less regulated and remote areas around the

world, we may be unable to proactively address these techniques or to implement adequate preventive measures. Security breaches could result in negative publicity, damage to reputation, exposure to risk of loss or litigation and possible liability due to regulatory penalties and sanctions. Security breaches could also cause travelers and potential users to lose confidence in our security, which would have a negative effect on the value of our brand. Failure to adequately protect against attacks or intrusions, whether for our own systems or systems of vendors, could expose us to security breaches that could have an adverse impact on financial performance.

We have acquired a number of companies over the years and may continue to do so in the future. While we make significant efforts to address any information technology security issues with respect to our acquisitions, we may still inherit such risks when we integrate the acquired businesses.

System interruption and the lack of redundancy in some of our internal information systems may harm our business.

We rely on computer systems to deliver content and services. We have experienced and may in the future experience system interruptions that make some or all of these systems unavailable or prevent us from efficiently providing content and services to users and third parties. Significant interruptions, outages or delays in internal systems, or systems of third parties that we rely upon, or deterioration in the performance of any such systems, would impair our ability to process transactions or display content and decrease the quality of the services we offer to travelers and users. These interruptions could include security intrusions and attacks on our systems for fraud or service interruption (called “denial of service” or “bot” attacks). Fire, flood, power loss, telecommunications failure, break-ins, earthquakes, acts of war or terrorism, acts of God, computer viruses, electronic intrusion attempts from both external and internal sources and similar events or disruptions may damage or impact or interrupt computer or communications systems or business processes at any time. If we experience frequent or persistent system failures, our reputation and brand could be permanently and significantly harmed.

Although we have put measures in place to protect certain portions of our facilities and assets, any of these events could cause system interruption, delays and loss of critical data, and could prevent us from providing content and services to users, travelers and/or third parties for a significant period of time. In addition, remediation may be costly and we may not have adequate insurance to cover such costs. Moreover, the costs of enhancing infrastructure to attain improved stability and redundancy may be time consuming and expensive and may require resources and expertise that are difficult to obtain.

We may have future capital needs and may not be able to obtain additional financing on acceptable terms.

We are currently party to a credit agreement with respect to a \$1.2 billion revolving credit facility maturing in May 2022, or (as more fully discussed above) the “2015 Credit Facility.” This agreement includes restrictive covenants that may impact the way we manage our business and may limit our ability to secure significant additional financing in the future on favorable terms. Our ability to secure additional financing and satisfy our financial obligations outstanding from time to time will depend upon our future operating performance, which is subject to then prevailing general economic and credit market conditions, including interest rate levels and the availability of credit generally, and financial, business and other factors, many of which are beyond our control. There can be no assurance that sufficient financing will be available on desirable or even any terms to fund investments, acquisitions, stock repurchases, dividends, debt refinancing or extraordinary actions or that counterparties in any such financings would honor their contractual commitments.

We have indebtedness which could adversely affect our business and financial condition.

We currently have outstanding \$265 million in long-term debt. Risks relating to our indebtedness include:

Increasing our vulnerability to general adverse economic and industry conditions;

- Requiring us to dedicate a portion of our cash flow from operations to principal and interest payments on our indebtedness, thereby reducing the availability of cash flow to fund working capital, capital expenditures, acquisitions and investments and other general corporate purposes;

Making it more difficult for us to optimally capitalize and manage the cash flow for our businesses;

Limiting our flexibility in planning for, or reacting to, changes in our businesses and the markets in which we operate;

Possibly placing us at a competitive disadvantage compared to our competitors that have less debt;

Limiting our ability to borrow additional funds or to borrow funds at rates or on other terms that we find acceptable; and

Exposing us to the risk of increased interest rates because our outstanding debt is expected to be subject to variable rates of interest.

In addition, it is possible that we may need to incur additional indebtedness in the future in the ordinary course of business. The terms of our 2015 Credit Facility allow us to incur additional debt subject to certain limitations; however, there is no assurance that additional financing will be available to us on terms favorable to us, if at all. In addition, if new debt is added to current debt levels, the risks described above could intensify.

Our 2015 Credit Facility provides for various provisions that limit our discretion in the operation of our business and require us to meet financial maintenance tests and other covenants and the failure to comply with their covenants could have a material adverse effect on us.

We are party to a credit agreement providing for our 2015 Credit Facility. The agreements that govern the 2015 Credit Facility contain various covenants, including those that limit our ability to, among other things:

- Incur indebtedness;
- Pay dividends on, redeem or repurchase our capital stock;
- Enter into certain asset sale transactions, including partial or full spin-off transactions;
- Enter into secured financing arrangements;
- Enter into sale and leaseback transactions; and
- Enter into unrelated businesses.

These covenants may limit our ability to optimally operate our business. In addition, our 2015 Credit Facility requires that we meet certain financial tests, including a leverage ratio test. Any failure to comply with the restrictions of our credit facility may result in an event of default under the agreements governing such facilities. Such default may allow the creditors to accelerate the debt incurred thereunder. In addition, lenders may be able to terminate any commitments they had made to supply us with further funds (including periodic rollovers of existing borrowings).

Our effective tax rate is impacted by a number of factors that could have a material impact on our financial results and could increase the volatility of those results.

Due to the global nature of our business, we are subject to income taxes in the United States and other foreign jurisdictions. In the event we incur net income in certain jurisdictions but incur losses in other jurisdictions, we generally cannot offset the income from one jurisdiction with the loss from another. This lack of flexibility increases our effective tax rate. Furthermore, significant judgment is required to calculate our worldwide provision for income taxes and depends on our ability to operate our business in a manner consistent with our corporate structure and intercompany arrangements. In the ordinary course of our business there are many transactions and calculations where the ultimate tax determination is uncertain.

We believe our tax estimates are reasonable. However, we are routinely under audit by federal, state and foreign taxing authorities. The taxing authorities of jurisdictions in which we operate may challenge our methodologies for valuing developed technology or intercompany arrangements, including our transfer pricing, or determine that the manner in which we operate our business does not achieve the intended tax consequences, which would increase our effective tax rate and harm our financial position and results of operations. As we operate in numerous taxing jurisdictions, the application of tax laws can also be subject to diverging and sometimes conflicting interpretations by taxing authorities of these jurisdictions. It is not uncommon for taxing authorities of different countries to have conflicting views, for instance, with respect to, among other things, the manner in which the arm's length standard is applied for transfer pricing purposes, or with respect to the valuation of intellectual property. The final determination of audits could be materially different from our income tax provisions and accruals and could have a material effect on our financial position, results of operations, or cash flows in the period or periods for which that determination is made.

Additionally, we continue to accumulate positive cash flows in foreign jurisdictions, which we consider indefinitely reinvested. Any repatriation of funds currently held in foreign jurisdictions may result in higher effective tax rates and incremental cash tax payments. In addition, there have been proposals to amend U.S. tax laws that would significantly impact the manner in which U.S. companies are taxed on foreign earnings. Although we cannot predict whether or in what form any legislation will pass, if enacted, it could have a material adverse impact on our U.S. tax expense and cash flows.

Changes in tax laws or tax rulings, or the examination of our tax positions, could materially affect our financial position and results of operations.

Tax laws are dynamic and subject to change as new laws are passed and new interpretations of the law are issued or applied. Our existing corporate structure and intercompany arrangements have been implemented in a manner we believe is in compliance with current prevailing tax laws. However, the tax benefits that we intend to eventually derive could be undermined due to changing tax laws. In particular, the current U.S. administration and key members of Congress have made public statements indicating that tax reform is a priority, resulting in uncertainty not only with respect to the future corporate tax rate, but also the U.S. tax consequences of income derived from income related to intellectual property earned overseas in low tax jurisdictions. Certain changes to U.S. tax laws, including, but not limited to, limitations on the ability to defer U.S. taxation on earnings outside of the United States until those earnings are repatriated to the United States, could affect the tax treatment of our foreign earnings.

In addition, the taxing authorities in the United States and other jurisdictions where we do business regularly examine our income and other tax returns as well as the tax returns of Expedia, our former parent. The ultimate outcome of these examinations (including the IRS audit described below) cannot be predicted with certainty. Should the IRS or other taxing authorities assess additional taxes as a result of examinations, we may be required to record charges to our operations, which could harm our business, operating results and financial condition.

In connection with the Spin-Off, we could be subject to significant tax liabilities.

Under the Tax Sharing Agreement between us and Expedia entered into in connection with the Spin-Off, we are generally required to indemnify Expedia for any taxes resulting from the Spin-Off (and any related interest, penalties, legal and professional fees, and all costs and damages associated with related stockholder litigation or controversies) to the extent such amounts resulted from (i) any act or failure to act by us described in the covenants in the tax sharing agreement, (ii) any acquisition of our equity securities or assets or those of a member of our group, or (iii) any failure of the representations with respect to us or any member of our group to be true or any breach by us or any member of our group of any covenant, in each case, which is contained in the separation documents or in the documents relating to the IRS private letter ruling and/or the opinion of counsel.

We continue to be responsible for potential tax liabilities in connection with consolidated income tax returns filed with Expedia prior to or in connection with the Spin-Off. By virtue of previously filed consolidated tax returns with Expedia, we are currently under an IRS audit for the 2009, 2010, and 2011 tax years. In connection with that audit, we received, in January 2017, notices of proposed adjustment from the IRS for the 2009 and 2010 tax years, which would result in an increase in our worldwide income tax expense. The proposed adjustments would result in an increase to our worldwide income tax expense in an estimated range totaling \$10 million to \$14 million for those specific years after consideration of competent authority relief, exclusive of interest and penalties. We are also subject to various ongoing state income tax audits. The outcome of these matters or any other audits could subject us to significant tax liabilities.

We are subject to fluctuation in foreign currency exchange risk.

We conduct a significant and growing portion of our business outside the United States but report our results in U.S. dollars. As a result, we face exposure to movements in foreign currency exchange rates, particularly those related to the Euro, British pound sterling, and Australian dollar. These exposures include, but are not limited to re-measurement of gains and losses from changes in the value of foreign denominated assets and liabilities; translation gains and losses on foreign subsidiary financial results that are translated into U.S. dollars upon consolidation; and planning risk related to changes in exchange rates between the time we prepare our annual and quarterly forecasts and when actual results occur.

Depending on the size of the exposures and the relative movements of exchange rates, if we were to choose not to hedge or were to fail to hedge effectively our exposure, we could experience a material adverse effect on our financial statements and financial condition. As seen in some recent periods, in the event of severe volatility in exchange rates the impact of these exposures can increase, and the impact on results of operations can be more pronounced. In addition, the current environment and the increasingly global nature of our business have made hedging these exposures both more complex. We hedge certain short-term foreign currency exposures with the purchase of forward exchange contracts. These forward exchange contracts only help mitigate the impact of changes in foreign currency rates that occur during the term of the related contract period and carry risks of counter-party failure. There can be no assurance that our forward exchange contracts will have their intended effects.

Significant fluctuations in foreign currency exchange rates can affect consumer travel behavior. Volatility in foreign currency exchange rates and its impact on consumer behavior, which may differ across regions, makes it more difficult to forecast industry and

consumer trends and the timing and degree of their impact on our markets and business, which in turn could adversely affect our ability to effectively manage our business and adversely affect our results of operations.

Liberty TripAdvisor Holdings, Inc. currently is a controlling stockholder.

Liberty TripAdvisor Holdings, Inc., or LTRIP, effectively controls the outcome of all matters submitted to a vote or for the consent of our stockholders (other than with respect to the election by the holders of our common stock of 25% of the members of our Board of Directors and matters as to which Delaware law requires separate class votes), including but not limited to, corporate transactions such as mergers, business combinations or dispositions of assets, the authorization or issuance of new equity or debt securities and determinations with respect to our business direction and policies. Our Chairman Greg Maffei, and one of our Directors Albert Rosenthaler also serve as officers and directors of LTRIP. LTRIP may have interests that differ from those of our other stockholders and they may vote in a way with which our other stockholders may not agree or that may be adverse to other stockholders' interests. LTRIP is not restricted from investing in other businesses involving or related to our business. Liberty's control of us, as well as the existing provisions of our organizational documents and Delaware law, may discourage or prevent a change of control that might otherwise be beneficial, which may reduce the market price of our common stock.

We are currently relying on the "controlled company" exemption under NASDAQ Stock Market Listing Rules, pursuant to which "controlled companies" are exempt from certain corporate governance requirements otherwise applicable under NASDAQ listing rules.

The NASDAQ Stock Market Listing Rules exempt "controlled companies," or companies of which more than 50% of the voting power is held by an individual, a group or another company, from certain corporate governance requirements, including those requirements that:

- A majority of the Board of Directors consist of independent directors;
- Compensation of officers be determined or recommended to the Board of Directors by a majority of its independent directors or by a compensation committee comprised solely of independent directors; and
- Director nominees be selected or recommended to the Board of Directors by a majority of its independent directors or by a nominating committee that is composed entirely of independent directors.

We currently rely on the controlled company exemption for certain of the above requirements. Accordingly, our stockholders will not be afforded the same protections generally as stockholders of other NASDAQ-listed companies with respect to corporate governance for so long as we rely on these exemptions from the corporate governance requirements.

If we are unable to successfully maintain effective internal control over financial reporting, investors may lose confidence in our reported financial information and our stock price and business may be adversely impacted.

As a public company, we are required to maintain internal control over financial reporting and our management is required to evaluate the effectiveness of our internal control over financial reporting as of the end of each fiscal year. Additionally, we are required to disclose in our Annual Reports on Form 10-K our management's assessment of the effectiveness of our internal control over financial reporting and a registered public accounting firm's attestation report on this assessment. If we are not successful in maintaining effective internal control over financial reporting, there could be inaccuracies or omissions in the consolidated financial information we are required to file with the SEC. Additionally, even if there are no inaccuracies or omissions, we could be required to publicly disclose the conclusion of our management that our internal control over financial reporting or disclosure controls and procedures are not effective. These events could cause investors to lose confidence in our reported financial information, adversely impact our stock price, result in increased costs to remediate any deficiencies, attract regulatory scrutiny or lawsuits that could be costly to resolve and distract management's attention, limit our ability to access the capital markets or

cause our stock to be delisted from NASDAQ or any other securities exchange on which we are then listed.

The market price and trading volume of our common stock may be volatile and may face negative pressure.

Our stock price has experienced, and could continue to experience in the future, substantial volatility. The market price of our common stock is affected by a number of factors, including the risk factors described in this section and other factors beyond our control. Factors affecting the trading price of our common stock could include:

- ◆ Quarterly variations in our or our competitors' results of operations;
- ◆ Changes in earnings estimates or recommendations by securities analysts;

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• Failure to meet market expectations;

• The announcement of new products or product enhancements by us or our competitors;

• Repurchases of our common stock pursuant to our share repurchase program which could also cause our stock price to be higher than it would be in the absence of such a program and could potentially reduce the market liquidity for our stock;

- Developments in our industry, including changes in governmental regulations; and

• General market conditions and other factors, including factors related to our operating performance or the operating performance of our competitors.

Furthermore, the stock markets have experienced price and volume fluctuations that have affected and continue to affect the market prices of equity securities of many companies. These fluctuations often have been unrelated or disproportionate to the operating performance of those companies. These broad market and industry fluctuations and general economic, political and market conditions, such as recessions, interest rate changes or foreign currency exchange fluctuations, may negatively impact the market price of our common stock regardless of our actual operating performance.

Future sales of shares of our common stock in the public market, or the perception that such sales may occur, may depress our stock price.

For the nine months ended September 30, 2017, the average daily trading volume of our common stock on NASDAQ was approximately 2.9 million shares. If our existing stockholders or their distributees sell substantial amounts of our common stock in the public market, the market price of the common stock could decrease significantly. The perception in the public market that our existing stockholders might sell shares of common stock could also depress the trading price of our common stock. In addition, certain stockholders have rights, subject to some conditions, to require us to file registration statements covering their shares or to include their shares in registration statements that we may file for ourselves or other stockholders. If LTRIP or some other stockholder sells substantial amounts of our common stock in the public market, or if there is a perception in the public market that LTRIP might sell shares of our common stock, the market price of our common stock could decrease significantly. A decline in the price of shares of our common stock might impede our ability to raise capital through the issuance of additional shares of our common stock or other equity securities.

Anti-takeover provisions in our organizational documents and Delaware law may discourage or prevent a change of control, even if an acquisition would be beneficial to our stockholders, which could affect our stock price adversely and prevent attempts by our stockholders to replace or remove our current management.

Our certificate of incorporation and bylaws contain provisions that could delay or prevent a change of control of our company or changes in our Board of Directors that our stockholders might consider favorable. These provisions include:

• Authorization and issuance of Class B common stock that entitles holders to ten votes per share;

• Authorization of the issuance of preferred stock which can be created and issued by the Board of Directors without prior stockholder approval, with rights senior to those of our common stock;

• Prohibiting our stockholders from filling board vacancies or calling special stockholder meetings; and

• Limiting who may call special meetings of stockholders.

We are subject to the provisions of Section 203 of the Delaware General Corporation Law, which may prohibit certain business combinations with stockholders owning 15% or more of our outstanding voting stock. These and other provisions in our certificate of incorporation, bylaws and Delaware law could make it more difficult for stockholders or potential acquirers to obtain control of our Board of Directors or initiate actions that are opposed by our then-current Board of Directors, including a merger, tender offer or proxy contest involving our company. Any delay

or prevention of a change of control transaction or changes in our Board of Directors could cause the market price of our common stock to decline.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Unregistered Sales of Equity Securities

During the quarter ended September 30, 2017, we did not issue or sell any shares of our common stock, Class B common stock or other equity securities pursuant to unregistered transactions in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended.

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Share Repurchases

On January 25, 2017, our Board of Directors authorized the repurchase of \$250 million of our shares of common stock under a new share repurchase program. Our Board of Directors authorized and directed management, working with the Executive Committee of our Board of Directors to affect the share repurchase program in compliance with applicable legal requirements.

As of June 30, 2017, we had repurchased a total of 6,079,003 shares of outstanding common stock under the share repurchase program at an average share price of approximately \$41.13, or \$250 million in the aggregate, and have completed this share repurchase program authorized by our Board of Directors. We did not repurchase any of our shares of common stock during the three months ended September 30, 2017.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

The exhibits listed below are filed as part of this Quarterly Report on Form 10-Q.

Exhibit No.	Exhibit Description	Filed Herewith	Incorporated by Reference			
			Form	SEC File No.	Exhibit	Filing Date
10.1+	<u>Executive Severance Plan and Summary Plan Description dated August 7, 2017</u>		10-Q	001-35362	10.4	8/8/17
31.1	<u>Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002</u>	X				
31.2	<u>Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002</u>	X				
		X				

- 32.1 Certification of the Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
- 32.2 Certification of the Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 X
- 101 The following financial statements from the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2017, formatted in XBRL: (i) Unaudited Condensed Consolidated Statements of Operations, (ii) Unaudited Condensed Consolidated Statements of Comprehensive Income, (iii) Unaudited Condensed Consolidated Balance Sheets, (iv) Unaudited Condensed Consolidated Statement of Changes in Stockholders' Equity, (v) Unaudited Condensed Consolidated Statements of Cash Flows, and (vi) Notes to Unaudited Condensed Consolidated Financial Statements. X

+ Indicates a management contract or a compensatory plan, contract or arrangement.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

TripAdvisor, Inc.

By: /s/ Ernst Teunissen
Ernst Teunissen
Chief Financial Officer

By: /s/ Noel Watson
Noel Watson
Chief Accounting Officer

November 6, 2017