GULFPORT ENERGY CORP
Form 10-K
March 01, 2013

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

Form 10-K
(Mark One)
ý ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012
OR
¨ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 000-19514
Gulfport Energy Corporation
(Exact Name of Registrant as Specified in Its Charter)

Delaware	73-1521290
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
14313 North May Avenue, Suite 100 Oklahoma City, Oklahoma	73134
(Address of Principal Executive Offices)	(Zip code)

(405) 848-8807
(Registrant's Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No ý
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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 definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ý Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of June 29, 2012, based on the closing price of the common stock on the NASDAQ Global Select Market on June 29, 2012, the last business day of the registrant’s most recently completed second fiscal quarter ($20.63 per share), was $1,148,840,242.35.

As of February 20, 2013, 77,339,886 shares of the registrant’s common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

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

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FORWARD-LOOKING STATEMENTS

Our disclosure and analysis in this Form 10-K may include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements by terms such as "may," "will," "should," "could," "would," "expects," "plans," "anticipates," "int "believes," "estimates," "projects," "predicts," "potential" and similar expressions intended to identify forward-looking statements. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as estimated future net revenues from oil and gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements.

These forward-looking statements are largely based on our expectations and beliefs concerning future events, 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 relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control.

Although we believe our 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, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Form 10-K are not guarantees of future performance, and we cannot assure any reader that those 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 factors listed in the "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" sections and elsewhere in this Form 10-K. All forward-looking statements speak only as of the date of this Form 10-K. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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PART I

ITEM 1. BUSINESS

General

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in the Utica Shale in Eastern Ohio. During 2010, we acquired our initial acreage position in the Niobrara Formation of Northwestern Colorado and, during 2011, we acquired our initial acreage position in the Utica Shale in Eastern Ohio. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, a 21.4% equity interest in Diamondback Energy, Inc., or Diamondback, a NASDAQ Global Select Market listed company to which we contributed our Permian Basin oil and gas interests in October 2012 immediately prior to Diamondback's initial public offering, or the Diamondback IPO (see “-Recent Developments-Contribution” below), and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

In 2012, at our WCBB field, we recompleted 61 wells and drilled 31 wells for a total cost of approximately $68.2 million as of December 31, 2012. Of the 31 new wells drilled at WCBB in 2012, 27 were completed as producing wells and four were non-productive. In the fourth quarter of 2012, production at WCBB was approximately 293,906 net barrels of oil equivalent, or BOE, or an average of 3,195 BOE per day, 98% of which was from oil and 2% of which was from natural gas. During January 2013, our average net daily production at WCBB was approximately 3,054 BOE, 98% of which was from oil and 2% of which was from natural gas. During 2013, we currently anticipate drilling 22 to 24 wells and recompleting 60 wells at our WCBB field for an estimated aggregate cost of $42.0 million to $45.0 million.

In 2012, at our East Hackberry field, we recompleted 32 wells and drilled 23 wells for a total cost of approximately $70.1 million as of December 31, 2012. Of the 23 new wells drilled at East Hackberry during 2012, 19 were completed as producing wells, three were non-productive and one was being drilled at year end. In the fourth quarter of 2012, net production at East Hackberry was approximately 212,975 BOE, or an average of 2,315 BOE per day, 98% of which was from oil and 2% of which was from natural gas. During January 2013, our average net daily production at East Hackberry was approximately 2,623 BOE, 97% of which was from oil and 3% of which was from natural gas. During 2013, we currently anticipate drilling ten to twelve wells and recompleting 24 wells for an aggregate estimated cost of $26.0 million to $28.0 million.

At December 31, 2012, we were drilling one well at our West Hackberry field. In the fourth quarter of 2012, net production at West Hackberry was approximately 4,711 BOE, or an average of 51 BOE per day, 96% of which was from oil and 4% of which was from natural gas. During January 2013, our average net daily production at West Hackberry was approximately 29 BOE, 100% of which was from oil.

As of December 31, 2012, we had acquired leasehold interests in approximately 137,000 gross (106,000 net) acres in the Utica Shale in Eastern Ohio, and in February 2013 we acquired an additional approximately 22,000 net acres in the Utica Shale. See "-Recent Developments - February 2013 Utica Acreage Acquisition." We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of December 31, 2012, had drilled 14 wells, ten of which had been completed. As of February 15, 2013, three of these wells were producing. Of the 11 additional wells, seven are projected to be producing by April 1, 2013 and the other four wells are projected to be producing by June 1, 2013. The delays in bringing these additional wells on-line have primarily been associated with MarkWest Energy Partners, L.P.'s challenges in obtaining rights-of-way and acquiring necessary state and federal permitting. These rights-of-way and permits have now been obtained. In addition, 12 gross (one net) wells were drilled by another operator on our Utica Shale acreage during 2012.

We have three rigs under contract on our Utica Shale acreage. We currently intend to drill 50 gross (44 net) wells on our Utica Shale acreage in 2013 for approximately $382.0 million to $426.0 million.

Aggregate net production from our Utica Shale acreage during the three months ended December 31, 2012 was approximately 69,667 BOE, or 757 BOE per day, 35% of which was from oil and natural gas liquids, or NGLs, and 65% of which was from natural gas. During January 2013, our average daily net production from the Utica Shale was approximately 792 BOE, 41% of which was from oil and NGLs and 59% of which was from natural gas. The Wagner 1-28H well, our longest producing well in the Utica Shale, was assigned gross proved estimated ultimate recovery reserves at December 31, 2012 of 65.8 thousand barrels of oil, or MBbls, and 10.0 billion cubic feet, or Bcf, of unshrunk natural gas by Ryder Scott Company,

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L.P., or Ryder Scott. Adjusting for shrinkage and the extraction of NGLs, we estimate that this is equivalent to 1.8 million BOE, or MMBOE, of proved reserves.

From January 1, 2012 through the closing of the contribution of our Permian Basin acreage to Diamondback on October 11, 2012, 19 gross (8.3 net) wells, including our first horizontal well, were spud on our Permian Basin acreage, all of which were completed as producing wells. One gross (0.3 net) existing well was recompleted from January 1, 2012 to October 11, 2012. Aggregate net production from our Permian Basin acreage during the first eleven days of October 2012 was approximately 17,100 BOE, or 1,555 BOE per day, of which approximately 60% was oil, 28% was NGL's and 12% was natural gas. For more information regarding the contribution of our Permian Basin acreage to Diamondback, see "-Recent Developments-Contribution" below.

Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in Northwestern Colorado and held leases for approximately 11,788 net acres as of December 31, 2012. During the year ended December 31, 2012, three gross (one net) wells, including one gross (.04 net) well drilled by another operator, were spud on our Niobrara Formation acreage, two of which were completed as producers and one of which was non-productive. In the fourth quarter of 2012, net production from our Niobrara Formation acreage was approximately 2,644 BOE, or an average of 29 BOE per day, 100% of which was from oil. During January 2013, our average net daily production from our Niobrara Formation acreage was approximately 43 BOE, 100% of which was from oil. In the Niobrara Formation, we have completed a 60 square mile 3-D seismic survey and have received a processed version of the seismic. During 2013, we currently do not anticipate drilling any wells in the Niobrara Formation.

As of December 31, 2012, we held approximately 864 net acres in the Bakken Formation of Western North Dakota and Eastern Montana with interests in nine wells and overriding royalty interests in certain existing and future wells. In the fourth quarter of 2012, our net production from this acreage was approximately 7,355 BOE, or an average of 80 BOE per day, of which 87% was from oil, 10% was from natural gas and 3% was from NGLs. During January 2013, our average daily net production from our Bakken Formation acreage was approximately 73 BOE, of which 89% was from oil and 11% was from natural gas.

We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. The remaining interest in Grizzly is owned by Grizzly Oils Sands Inc., an entity owned by certain investment funds managed by Wexford Capital LP, or Wexford. An affiliate of Wexford owned approximately 13.3% of our outstanding common stock as of December 5, 2011, and approximately 9.5% as of March 13, 2012, which ownership was reduced to less than 1% as of September 28, 2012. As of December 31, 2012, Grizzly had approximately 800,000 acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada. Our total net investment in Grizzly was approximately $172.8 million as of December 31, 2012. As of that date, Grizzly had drilled an aggregate of 233 core holes and six water supply test wells on ten separate lease blocks and conducted a number of seismic programs. In March 2010, Grizzly filed an application for the development of an 11,300 barrel per day oil sand project at Algar Lake. In November 2011, the Government of Alberta provided a formal Order in Council authorizing the Alberta Energy Resources Conservation Board, or ERCB, to issue the formal regulatory approval of Grizzly's Algar Lake steam-assisted gravity drainage, or SAGD, project. Construction of the Algar Lake Phase 1 SAGD project commenced in 2012. During 2012, an 11 kilometer road was constructed to the project site, water and natural gas supply pipelines were installed, central plant modules were assembled, transported to the project site and lifted into place, ten production well pairs were drilled and completed and well pad modules and flow lines back to the central plant were installed. Grizzly expects first oil production at Algar Lake by the third quarter of 2013. In the first quarter of 2012, Grizzly completed the acquisition of the May River property comprising approximately 47,000 acres. In the fourth quarter of 2012, Grizzly initiated a 28 well core hole drilling program at May River and plans to file an initial 12,000 barrel per day development application with the ERCB by the end of 2013. At the Thickwood thermal project, Grizzly's 2012 activities included the completion of a 22 well core hole drilling program and the acquisition of 31 kilometers of seismic data. A development application for a 12,000 barrel per day oil sands project at Thickwood was filed in the fourth quarter of 2012. Grizzly anticipates approval of this development application in mid-2014 and first oil production by mid-2017. Grizzly has also entered into a memorandum of understanding that outlines the rate structure for a ten year agreement with Canadian National Railway Company, or CN, to transport its bitumen to the U.S. Gulf Coast via CN's rail network. Grizzly expects that this arrangement will provide consistent access to Brent-based pricing from Grizzly's Algar Lake project. Grizzly is also pursuing the design, permitting and construction of rail terminals in Northern Alberta and on the Lower Mississippi River, where it plans to develop scalable capacity to accommodate unit trains to ship and receive up to 100,000 barrels per day. Grizzly anticipates beginning to transport the company's bitumen starting in the third quarter of 2013.

We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II. The remaining interests in Tatex II are owned by entities controlled by Wexford. Tatex II, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO,

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LLC, or APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 243,000 acres which includes the Phu Horm Field. We also own a 17.9% ownership interest in Tatex Thailand III, LLC, or Tatex III. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. Tatex III owns a concession covering approximately 490,000 acres in Southeast Asia. In 2009, Tatex III completed a 3-D seismic survey on this concession. The first well was drilled on our concession in 2010 and was temporarily abandoned pending further scientific evaluation. Drilling of the second well concluded in March 2011. The second well was drilled to a depth of 15,026 feet and logged approximately 5,000 feet of apparent possible gas saturated column. The well experienced gas shows and carried a flare measuring up to 25 feet throughout drilling below the intermediate casing point of 9,695 feet. During testing, the well produced at rates as high as 16 million cubic feet, or MMcf, per day of gas for short intervals, but would subsequently fall to a sustained rate of two MMcf per day of gas. Pressure buildup information confirmed that this wellbore lacked the permeability to deliver commercial quantities of gas. Despite an apparently well-developed porosity system suggesting potential for a large amount of gas in place, testing of the well did not exhibit that there was sufficient permeability to produce in commercial quantities. Tatex III intends to continue testing some of the structures identified through its 3-D seismic survey and has begun the application process for two more drilling locations. Tatex III currently expects to drill the first of these wells, located to the south of the TEW-E well, in 2013.

In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In the second quarter of 2012, we acquired a 50% equity interest in each of Stingray Pressure Pumping LLC, or Stingray Pressure, and Stingray Cementing LLC, or Stingray Cementing. Stingray Pressure and Stingray Cementing provide well completion services. We also acquired a 50% equity interest in Blackhawk Midstream LLC, or Blackhawk, which coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage. In March 2012, we acquired a 50% equity interest in Timber Wolf Terminals LLC, or Timber Wolf, for $1.0 million. Also in March 2012, we acquired a 22.5% equity interest in Windsor Midstream LLC, or Midstream, for $7.0 million. Midstream owns a 28.4% equity interest in a gas processing plant in West Texas. In the fourth quarter of 2012, we acquired a 50% equity interest in Stingray Logistics LLC, or Stingray Logistics, which will provide well services. In 2011, we acquired a 25% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates drilling rigs and related equipment. In April 2012, we purchased an additional 15% equity interest in Bison for approximately $6.2 million, bringing our total ownership interest in Bison to 40%. Also in 2011, we acquired a 25% interest in Muskie Holdings LLC, or Muskie, which is engaged in the mining of hydraulic fracturing grade sand. The remaining equity interests in these entities are owned by affiliates of Wexford. In 2012, we invested approximately $42.8 million in these entities. In 2013, we expect to invest approximately $10.0 million to $15.0 million in these entities.

As of December 31, 2012, we had 13.9 million barrels of oil equivalent, or MMBOE, of proved reserves with a present value of estimated future net revenues, discounted at 10%, or PV-10, of approximately $436.8 million and associated standardized measure of discounted future net cash flows of approximately $348.6 million, excluding reserves attributable to our interests in Diamondback, Grizzly, Tatex II and Tatex III. See "Item 2. Properties-Proved Oil and Natural Gas Reserves" for our definition of PV-10, a non-GAAP financial measure, and a reconciliation of our standardized measure of discounted future net cash flows to PV-10.

Recent Developments

February 2013 Utica Acreage Acquisition

On February 11, 2013, we entered into a purchase and sale agreement, or the PSA, with Windsor Ohio, LLC, or Windsor Ohio, which is an affiliate of Wexford, pursuant to which Windsor Ohio agreed to sell, assign, transfer and convey to us approximately 22,000 net acres representing 100% of its right, title and interest in and to certain leasehold interests in the Utica Shale in Eastern Ohio for approximately $220.4 million, subject to certain adjustments. This transaction, which closed on February 15, 2013, excluded Windsor Ohio's interest in 14 existing wells and 16 proposed future wells together with certain acreage surrounding these wells. We acquired our initial acreage in the

Utica Shale in February 2011 and subsequently acquired additional acreage in the area. Windsor Ohio participated with us in the acquisition of these leases. Through a prior transaction with Windsor Ohio, as discussed below under the heading "—December 2012 Utica Acreage Acquisition," we acquired approximately 37,000 net acres, which increased our working interest in the acreage at the time to 77.7%. Through this most recent transaction, we acquired an additional approximately 16.2% interest in these leases, increasing our working interest in the acreage to 93.8%. All of the acreage included in this transaction is currently nonproducing and we are the operator of all of this acreage, subject to existing development and operating agreements between the parties.

Pending the completion of title review after the closing, approximately $33.6 million of the purchase price has been placed

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in an escrow account. The escrow account will terminate on May 1, 2013 and the escrow amount will be distributed to either us or Windsor Ohio based on any title benefits or title defects resulting from the title review. Pursuant to the PSA, we and Windsor Ohio have agreed to indemnify each other, our respective affiliates and their respective officers, directors, employees and agents from and against all losses that such indemnified parties incur arising from any breach of representations, warranties or covenants in the PSA and certain other matters. The transaction was approved by a special committee of our board of directors, who engaged independent counsel and financial advisors to assist with their review.

December 2012 Utica Acreage Acquisition

On December 17, 2012, we entered into a purchase and sale agreement with Windsor Ohio, pursuant to which Windsor Ohio agreed to sell, assign, transfer and convey to us approximately 30,000 net acres which, at the time, represented 50% of its right, title and interest in and to certain leasehold interests in the Utica Shale in Eastern Ohio. On December 19, 2012, the parties amended that agreement to provide for our acquisition of approximately 7,000 additional net acres. The aggregate purchase price for these interests was approximately $372.0 million, subject to certain adjustments. As discussed above, we acquired our initial acreage in the Utica Shale in February 2011 and subsequently acquired additional acreage in the area. Windsor Ohio has participated with us in the acquisition of these leases and through this transaction, we acquired an additional approximately 27.5% interest in these leases, increasing our working interest in the acreage to 77.7%. The transaction closed on December 24, 2012. All of the acreage included in this transaction is nonproducing and we are the operator of all of this acreage, subject to existing development and operating agreements between the parties. Pending the completion of title review after the closing, approximately $53.9 million of the purchase price was placed in an escrow account. The escrow account will terminate on April 30, 2013 and the escrow amount will be distributed to either us or Windsor Ohio based on any title benefits or title defects resulting from the title review.

Contribution

On May 7, 2012, we entered into a contribution agreement with Diamondback, which is an affiliate of Wexford. Under the terms of the contribution agreement, we agreed to contribute to Diamondback, prior to the closing of the Diamondback IPO, all of our oil and gas interests in the Permian Basin. On October 11, 2012, we completed this contribution, which we refer to in this Annual Report as the Contribution. At the closing of the Contribution, Diamondback issued to us (i) 7,914,036 shares of Diamondback common stock and (ii) a promissory note for $63.6 million, which was repaid to us at the closing of the Diamondback IPO on October 17, 2012. This aggregate consideration was subject to a post-closing cash adjustment based on changes in the working capital, long-term debt and certain other items of a Diamondback subsidiary as of the date of the Contribution. In January 2013, we received an additional payment from Diamondback of $18.6 million as a result of this post-closing adjustment. As of December 11, 2012, Wexford beneficially owned approximately 44.4% of Diamondback's outstanding common stock.

In connection with the Contribution, we and Diamondback entered into an investor rights agreement in which we have the right, for so long as we beneficially own more than 10% of Diamondback's outstanding common stock, to designate one individual as a nominee to serve on Diamondback's board of directors. Such nominee, if elected to Diamondback's 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 of the board. So long as we have the right to designate a nominee to Diamondback's board and there is no nominee of ours actually serving as a Diamondback director, we will have the right to appoint one individual as an advisor to the board who shall be entitled to attend board and committee meetings. We are also entitled to certain information rights and Diamondback granted us certain demand and "piggyback" registration rights obligating Diamondback to register with the Securities and Exchange Commission, or the SEC, any shares of Diamondback common stock that we own. Immediately upon completion of the Contribution, we owned a 35% equity interest in Diamondback, rather than leasehold interests in our Permian Basin acreage. Upon completion of the Diamondback IPO and the exercise in full by the underwriters of their over-allotment option to purchase additional shares of common stock of Diamondback, we owned approximately 21.4% of

Diamondback's outstanding common stock. Our investment in Diamondback is accounted for as an equity method investment.
Notes Offerings
On October 17, 2012, we issued $250.0 million in aggregate principal amount of 7.750% Senior Notes due 2020, or the October Notes, to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act under an indenture among us, our subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee, which indenture we refer to as the senior note indenture. The offering of the October Notes is referred to herein as the October Notes Offering. On December 21, 2012, we issued an additional $50.0 million in aggregate principal amount of 7.750% Senior Notes due 2020, or the December Notes, to qualified institutional

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buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act, which offering we refer to herein as the December Notes Offering. The December Notes were issued as additional securities under the senior note indenture. The October Notes and the December Notes are referred to collectively herein as the Notes, and we refer to the October Notes Offering and the December Notes Offering collectively as the Notes Offerings.

Under the senior note indenture, interest on the Notes accrues at a rate of 7.750% per annum on the outstanding principal amount from October 17, 2012, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2013. The Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior in right of payment to any of our future subordinated indebtedness. All of our existing and future restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt guarantee the Notes, provided, however, that the Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of our future unrestricted subsidiaries. For more information regarding the Notes, see Item 7. “Management's Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and Capital Resources-Senior Notes.”

Equity Offerings

On December 24, 2012, we issued and sold 11,750,000 shares of our common stock in an underwritten public offering, or the December 2012 Equity Offering (including the partial exercise of an over-allotment option for 1,650,000 shares granted to the underwriters, which option was exercised to the extent of 750,000 shares). The underwriters subsequently exercised their option to purchase the remaining 900,000 additional shares of common stock subject to the over-allotment option at a second closing, which occurred on January 7, 2013. The net proceeds from the December 2012 Equity Offering (including the net proceeds from the sale of the shares of common stock to the underwriters under their over-allotment option) were approximately $460.7 million. We used a portion of these net proceeds to fund the acquisition of approximately 37,000 net acres in the Utica Shale in Eastern Ohio, as described above under the caption “—December 2012 Utica Acreage Acquisition.” The remaining net proceeds will be used for general corporate purposes, including the funding of a portion of our 2013 capital development plan.

On February 15, 2013, we issued and sold 8,912,500 shares of our common stock (including the 1,162,500 shares issued upon the exercise in full of an over-allotment option granted to the underwriters) in an underwritten public offering, which we refer to in this report as the February 2013 Equity Offering. The net proceeds from the February 2013 Equity Offering were approximately $325.8 million. We used a portion of these net proceeds to fund the acquisition of approximately 22,000 net acres in the Utica Shale in Eastern Ohio, as described above under the caption “-February 2013 Utica Acreage Acquisition.” The remaining net proceeds will be used for general corporate purposes, including the funding of a portion of our 2013 capital development plan.

Senior Secured Credit Facility

Effective as of October 17, 2012, in connection with the completion of the October Notes Offering and the Contribution, our borrowing base under our senior secured credit facility was set at $45.0 million until the next borrowing base redetermination. Upon completion of the December Notes Offering, our borrowing base was further reduced to $40.0 million. As of December 31, 2012, no borrowings were outstanding under our senior secured credit facility.

Principal Oil and Natural Gas Properties

The following table presents certain information as of December 31, 2012 reflecting our net interest in our principal producing oil and natural gas properties along the Louisiana Gulf Coast, in the Utica Shale in Eastern Ohio, in the Niobrara Formation in Northwestern Colorado and in the Bakken Formation in Western North Dakota and Eastern Montana.

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Field	NRI/WI (1)	Productive Wells (2)		Non-Productive Wells		Developed Acreage (3)		Proved Reserves		
								Gas	Oil	Total
	Percentages	Gross	Net	Gross	Net	Gross	Net	MBOE	MBOE	MBOE
West Cote Blanche Bay Field (4)	80.108/100	109	109	181	181	5,668	5,668	556	4,266	4,822
E. Hackberry Field (5)	80.309/100	41	41	96	96	3,931	3,931	151	1,900	2,051
W. Hackberry Field	83.333/100	3	3	23	23	1,192	1,192	3	95	98
Utica Shale (6)	40.641/50.0	2	1	—	—	2,441	1,800	4,886	1,702	6,588
Niobrara Formation	36.2/41.5	7	3	2	1	2,807	1,404	16	204	220
Bakken Formation (7)	2.7/2.9	8	0.2	—	—	1,862	163	10	82	92
Overrides/Royalty Non-operated	Various	208	0.4	2	0.06	—	—	6	2	8
Total		378	157.6	304	301.06	17,901	14,158	5,628	8,251	13,879

(1) Net Revenue Interest (NRI)/Working Interest (WI) for producing wells.
(2) Includes seven gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 11% of our acreage is developed acreage and has been perpetuated by production.
(4) We have a 100% working interest (80.108% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(5) NRI shown is for producing wells.
(6) Does not give effect to our February 2013 acquisition of approximately 22,000 additional net acres. See "—Recent Developments-February 2013 Utica Acreage Acquisition."
(7) NRI/WI is from wells that have been drilled or in which we have elected to participate.

West Cote Blanche Bay Field

Location and Land

The WCBB field is located approximately five miles off the coast of Louisiana in a shallow bay with water depths averaging eight to ten feet. We own a 100% working interest (80.108% net revenue interest, or NRI), and are the operator, in depths above the base of the 13900 Sand which is located at 11,320 feet. In addition, we own a 40.40% non-operated working interest (29.95% NRI) in depths below the base of the 13900 Sand, which is operated by Chevron Corporation. Our leasehold interests at WCBB contain 5,668 gross acres.

Area History and Production

Texaco, now Chevron Corporation, drilled the discovery well in this field in 1940 based on a seismic and gravitational anomaly. WCBB was subsequently developed on an even 160-acre pattern for much of the remainder of the decade. Developmental drilling continued and reached its peak in the 1970s when over 300 wells were drilled in the field. Of the 1,025 wells drilled as of December 31, 2012, 927 were completed as producing wells. As a result, the field has a historic success rate of 90% for all wells drilled. From the date of our acquisition of WCBB in 1997 through December 31, 2012, we drilled 214 new wells, 193 of which were productive, for a 90% success rate. As of December 31, 2012, estimated field cumulative gross production was 194.0 MMBOE and 236.9 Bcf of gas. Of the 1,025 wells drilled in WCBB as of December 31, 2012, 102 were producing, 181 were shut-in, seven were producing intermittently and five were being used as salt water disposal wells. The other 730 wells have been plugged and abandoned.

In 1991, Texaco conducted a 70 square mile 3-D seismic survey with 1,100 shot points per mile that processed out 100 fold. In 1993, an undershoot survey around the crest and production facilities was completed. We own the rights to the seismic data. In December 1999, we completed the reprocessing of the seismic data and our technical staff developed prospects from the data. The reprocessed data has enabled us to identify prospects in areas of the field that would have otherwise remained obscure. During the first half of 2005, we again reprocessed the seismic data using advanced seismic data processing.

Geology

WCBB overlies one of the largest salt dome structures on the Gulf Coast. The field is characterized by a piercement salt dome, which created traps from the Pleistocene through the Miocene formations. The relative movements affected deposition

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and created a complex system of fault traps. The compensating fault sets generally trend northwest to southeast and are intersected by sets having a major radial component. Later-stage movement caused extension over the dome and a large graben system (a downthrown area bounded by normal faults) was formed.

There are over 100 distinct sandstone reservoirs recognized throughout most of the field, and nearly 200 major and minor discrete intervals have been tested. Within the 1,025 wells that had been drilled in the field as of December 31, 2012, over 4,000 potential zones have been penetrated. These sands are highly porous and permeable reservoirs primarily with a strong water drive.

WCBB is a structurally and stratigraphically complex field. All of the proved undeveloped, or PUD, locations at WCBB are adjacent to faults and abut at least one fault. Our drilling programs are designed to penetrate each PUD trap with a new wellbore in a structurally optimum position, usually very close to the fault seal. The majority of these wells have been, and new wells drilled in connection with our drilling programs will be, directionally drilled using steering tools and downhole motors. The tolerance for error in getting near the fault is low, so the complex faulting does introduce the risk of crossing the fault before encountering the zone of interest, which could result in part or all of the zone being absent in the borehole. This, in turn, can result in lower than expected or no reserves for that zone. The new wellbores eliminate the mechanical risk associated with trying to produce the zone from an old existing wellbore, while the wellbore locations are selected in an effort to more efficiently drain each reservoir. The vast majority of the PUD targets are up-dip offsets to wells that produced from a sub-optimal position within a particular zone. Our inventory of prospects at WCBB as of December 31, 2012 included 36 PUD wells. The drilling schedule used in the reserve report anticipates that all of those wells will be drilled by 2015.

Facilities

We own and operate a production facility at WCBB that includes four production tank batteries, eight natural gas compressors, a storage barge facility, a dock, a dehydration unit and a salt water disposal system.

Recent and Future Activity

In 2012, we recompleted 61 gross and net wells and drilled 31 gross and net wells at WCBB. Of the 31 new wells drilled at WCBB in 2012, 27 were completed as producers and four were non-productive. As of February 15, 2013, we had recompleted 12 wells during 2013. Of the 31 wells drilled in 2012, 26 were considered deep wells. The 27 productive wells, with total depths ranging from 2,500 to 10,697 feet, have approximately 1,818 feet of aggregate apparent net pay. We currently anticipate drilling 22 to 24 gross and net wells and recompleting 60 gross and net wells at WCBB during 2013.

Production Status

In the fourth quarter of 2012, our production at WCBB was approximately 293,906 net BOE, or an average of 3,195 BOE per day, 98% of which was from oil and 2% of which was from natural gas. From January 1, 2013 through January 31, 2013, our average net daily production at WCBB was approximately 3,054 BOE, 98% of which was from oil and 2% of which was from natural gas. As there was no production from new wells brought on line in January 2013, the decrease in average net daily production was due to normal production declines.

East Hackberry Field

Location and Land

The East Hackberry field in Louisiana is located along the western shore and the land surrounding Lake Calcasieu, 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 80.309% average NRI) in certain producing oil and natural gas properties situated in the East Hackberry field. As of December 31, 2012, we held beneficial interests in approximately 4,512 acres, including the Erwin Heirs Block, which is located on land, and the adjacent State Lease 50 Block, which is located primarily in the shallow waters of Lake Calcasieu. We licensed approximately 54 square miles of 3-D seismic data covering a portion of the area and have received a processed version of the seismic data.

Area History and Production

The East Hackberry field was discovered in 1926 by Gulf Oil Company, now Chevron Corporation, by a gravitational anomaly survey. The massive shallow salt stock presented an easily recognizable gravity anomaly indicating a productive field. Initial production began in 1927 and has continued to the present. The estimated cumulative oil and condensate production

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through 2012 was over 2,754 MBOE and 330 Bcf of casinghead gas production. A total of 239 wells have been drilled on our portion of the field. As of December 31, 2012, 41 wells had daily production, 96 were shut-in and two had been converted to salt water disposal wells. The remaining 100 wells had been plugged and abandoned.

Geology

The Hackberry field is a major salt intrusive feature, elliptical in shape as opposed to a classic "dome," divided into east and west field entities by a saddle. Structurally, our East Hackberry acreage is located on the eastern end of the Hackberry salt ridge. There are over 30 pay zones at this field. The salt intrusion formed a series of structurally complex and steeply dipping fault blocks in the Lower Miocene and Oligocene age rocks. These fault blocks serve as traps for hydrocarbon accumulation. Our wells currently produce from perforations found between 5,100 and 12,200 feet.

Facilities

We have a field office that serves both the East and West Hackberry fields. In addition, we own and operate three production facilities at East Hackberry that include two land based tank batteries, a production barge, four natural gas compressors, dehydration units and salt water disposal systems.

Recent and Future Activity

During 2012 at East Hackberry, we recompleted 32 gross and net wells and drilled 14 gross and net land wells and nine gross and net wells on water. Of the 23 wells drilled during 2012, 19 were completed as producing wells, three were non-productive and one was being drilled at year end. As of February15, 2013, we had recompleted two wells during 2013, drilled two wells and were in the process of drilling one additional well in our East Hackberry field. We currently intend to drill ten to twelve gross and net wells and recomplete 24 gross and net wells in our East Hackberry field during 2013.

Production Status

In the fourth quarter of 2012, our net production at East Hackberry was approximately 212,975 BOE, or an average of 2,315 BOE per day, 98% of which was from oil and 2% of which was from natural gas. From January 1, 2013 through January 31, 2013, our average net daily production at East Hackberry was approximately 2,623 BOE, 97% of which was from oil and 3% of which was from natural gas. The increase in production in 2013 is a result of our 2012 drilling activities.

West Hackberry Field

Location and Land

The West Hackberry field is located on land and is five miles west of Lake Calcasieu in Cameron Parish, Louisiana, approximately 85 miles west of Lafayette and 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 83.333% NRI) in 1,192 acres within the West Hackberry field. Our leases at West Hackberry are located within two miles of one of the United States Department of Energy's Strategic Petroleum Reserves.

Area History

The first discovery well at West Hackberry was drilled in 1938 and the field was developed by Superior Oil Company, now ExxonMobil Corporation, between 1938 and 1988. The estimated cumulative oil and condensate production through 2012 was 307 MBOE and 140 Bcf of natural gas. There have been 37 wells drilled to date on our portion of West Hackberry. Currently, three of such wells are producing, 23 are shut-in and one has been converted to a saltwater disposal well. The remaining ten wells have been plugged and abandoned. At December 31, 2012, we were drilling one well at our West Hackberry field.

Geology

Structurally, our West Hackberry acreage is located on the western end of the Hackberry salt ridge. There are over 30 pay zones at this field. West Hackberry consists of a series of fault-bounded traps in the Oligocene-age Vincent and Keough sands associated with the Hackberry Salt Ridge. Recoveries from these thick, porous, water-drive reservoirs have resulted in per well cumulative production of almost 700 MBOE.

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Production Status

In the fourth quarter of 2012, our net production at West Hackberry was approximately 4,711 BOE, or an average of 51 BOE per day. From January 1, 2013 through January 31, 2013, our average net daily production at West Hackberry was approximately 29 BOE and was 100% from oil.

Facilities

We own and operate a production facility at West Hackberry that includes a land based tank battery and salt water disposal system.

Utica Shale (Eastern Ohio)

Location and Land

As of December 31, 2012, we had acquired leasehold interests in approximately 137,000 gross (106,000 net) acres in the Utica Shale in Eastern Ohio, including the approximately 37,000 net acres acquired in December 2012. In February 2013, we acquired approximately 22,000 additional net acres in the Utica Shale. See "-Recent Developments-February 2013 Utica Acreage Acquisition."

Area History

Based on the estimates published by the Ohio Department of Natural Resources, or ODNR, in 2012, the Utica Shale has a recoverable potential of 1.3 billion to 5.5 billion barrels of oil and 3.8 to 15.7 trillion cubic feet of natural gas in Ohio alone. During 2012, a number of oil and gas companies made significant investments in acquiring Utica Shale acreage in Eastern Ohio. As of February 9, 2013, the ODNR reported that in the Utica Shale in Ohio there were 65 producing horizontal wells, 236 horizontal wells that had been drilled but were not yet completed or connected to a pipeline, 15 horizontal wells that were being drilled and an additional 272 horizontal wells that had been permitted. During 2012, most of the drilling activity in the Utica Shale occurred in Eastern Ohio, where our acreage is located. Based on the initial drilling results, the Utica Shale is prospective for oil and NGLs. Specifically, early wells drilled in the Utica Shale indicated potential for production of significant amounts of NGLs, which generally have a higher value, on an energy-equivalent basis, than natural gas.

Geology

The Utica Shale is located in the Appalachian Basin of the United States and Canada. The Utica Shale is a rock unit comprised of organic-rich calcareous black shale that was deposited about 440 million to 460 million years ago during the Late Ordovician period. It overlies the Trenton Limestone and is located a few thousand feet below the Marcellus Shale, which is estimated to be the largest exploration play in the Eastern United States.

Recently, the application of horizontal drilling, combined with multistaged hydraulic fracturing to create permeable flow paths from wellbores into shale units, has resulted in increased drilling activity and production in the Devonian-age Marcellus Shale in the Appalachian Basin states of Pennsylvania, West Virginia, Southern New York and Eastern Ohio. This proven technology has potential for application in other shale units, such as the Ordovician-age Utica Shale, which extends across much of the Appalachian Basin region.

The Utica Shale is estimated to be thicker and more geographically extensive than the Marcellus Shale. The potential source rock portion of the Utica Shale underlies portions of Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, West Virginia and Virginia in the United States and is also present beneath parts of Lake Ontario, Lake Erie and Ontario, Canada. Throughout the potential source rock area, the Utica Shale ranges in thickness from less than 100 feet to over 500 feet. Over the rock unit as a whole, there is a general thinning from east to west.

The Utica Shale is also significantly deeper than the Marcellus Shale. In some parts of Pennsylvania, the Utica Shale is estimated to be over two miles below sea level and up to 7,000 feet below the Marcellus Shale. However, the depth of the Utica Shale decreases to the west into Ohio and to the northwest under the Great Lakes and into Canada to less than 2,000 feet below sea level.

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The Utica Shale is estimated to have higher carbonate and lower clay mineral content than the Marcellus Shale. The difference in mineralogy generally produces a different response to hydraulic fracturing treatments. Based on early fracturing results in the Utica Shale, the hydraulic fracturing methods used in the Marcellus Shale are less productive when applied in the Utica Shale. However, drillers have improved the fracturing rates in other gas shales with similar carbonate content. For example, drillers have discovered methods to make the brittle carbonate zones fracture at higher rates than other gas shale rock units in the Eagle Ford Shale in Texas. Drillers are researching methods to make similar fracturing improvements in the Utica Shale.

Facilities

There are typical land oil and gas processing facilities in the Utica Shale. We will be required to build facilities located at well locations including storage tank batteries, oil/gas/water separation equipment, vapor recovery line heaters and compression.

Recent and Future Activities

We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of December 31, 2012, had drilled 14 wells, ten of which had been completed. As of February 15, 2013, three of these wells were producing. Of the 11 additional wells, seven are projected to be producing by April 1, 2013 and the other four wells are projected to be producing by June 1, 2013. The delays in bringing these additional wells online have primarily been associated with MarkWest Energy Partners, L.P.'s challenges in obtaining rights-of-way and acquiring necessary state and federal permitting. These rights-of-way and permits have now been obtained. In addition, 12 gross (one net) wells were drilled by another operator on our Utica Shale acreage during 2012. In February 2013, we acquired approximately 22,000 additional net acres in the Utica Shale.

We have three rigs under contract on our Utica Shale acreage. We currently intend to drill 50 gross (44 net) wells on our Utica Shale acreage in 2013.

Production Status

Aggregate net production from the Utica Shale during the three months ended December 31, 2012 was approximately 69,667 BOE, or 757 BOE per day, 35% of which was from oil and NGLs and 65% of which was from natural gas. During January 2013, our average daily net production from the Utica Shale was approximately 792 BOE, 41% of which was from oil and NGLs and 59% of which was from natural gas. The Wagner 1-28H well, our longest producing well in the Utica Shale, was assigned gross proved estimated ultimate recovery reserves at December 31, 2012 of 65.8 MBbls of oil and 10.0 Bcf of unshrunk natural gas by Ryder Scott. Adjusting for shrinkage and the extraction of NGLs, we estimate that this is equivalent to 1.8 MMBOE of proved reserves.

Permian Basin (West Texas)

Location and Land

In 2007, we acquired approximately 4,100 net acres in West Texas in the Permian Basin with production at the time of acquisition from 32 gross (16 net) wells, predominately in the Wolfcamp formation. Subsequently, we acquired approximately 14,100 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 18,200 net acres as of September 30, 2012. From our initial acquisition in the Permian Basin through the contribution of our Permian Basin acreage to Diamondback on October 11, 2012, 118 gross (53.7 net) wells were drilled on our leasehold acreage in this area, primarily targeting the Wolfberry formation. We were not the operator of our Permian Basin acreage but were actively involved in the planning and execution of the drilling plans governed by a joint operating agreement with a subsidiary of Diamondback, which is the operator in this field. From January 1, 2012 through the closing of the contribution of our Permian Basin acreage to Diamondback on October 11, 2012, 19 gross (8.3 net) wells, including our first horizontal well, were spud on our Permian Basin acreage, all of which were completed as producing wells. One gross (0.3 net) existing well was recompleted from January 1, 2012 to October 11, 2012. Aggregate net production from our Permian Basin acreage during the first eleven days of October 2012 was approximately 17,100 BOE, or 1,555 BOE per day, of which approximately 60% was oil, 28% was NGLs and 12%

was natural gas.

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. The terrain in the Permian Basin is semi-arid mesquite-mixed grassland steppe.

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Area History

The Permian Basin formed as an area of rapid Mississippian-Pennsylvanian subsidence in the foreland of the Ouachita Foldbelt. The Wolfcamp play was a long-established reservoir in West Texas, first found in the 1950s as wells aiming for deeper targets occasionally intersected slump blocks or reef facies with reservoir properties. Exploration with 2-D seismic located additional fields, but it was not until the use of 3-D seismic in the 1990s that the greater extent of the Wolfcamp prospects was revealed. During the late 1990s, Arco began a drilling program targeting the Spraberry formation at 10,000 feet and then drilled another 200 to 300 feet to pick up the upper part of the Wolfcamp formation. Henry Petroleum, a private firm, owned interest 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 as Devonian wells. Henry Petroleum mapped the trend and began acquiring acreage and drilling wells using multiple slick-water fracs 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 decided to monetize approximately 15% of their acreage position which enabled us to participate in this play. Recent advancements in enhanced recovery techniques continue to make the basin an active play for exploration and production companies.

Geology

The Wolfcamp/Spraberry play, which we refer to as Wolfberry, of the Midland Basin lies in the area where the historically productive Spraberry trend geographically overlaps the productive area of the emerging Wolfcamp carbonate play. The Wolfcamp is characterized by an approximately 2,000 feet section of organic rich basin floor debris flows shed from the Central Basin Platform. The best reservoir rock within the section is generally found in close proximity to the Central Basin Platform.

Facilities

There are typical land oil and natural gas processing facilities in the Permian Basin. The facilities located at well locations included storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and Future Activity

As discussed above under the heading “-Recent Developments-Contribution,” on October 11, 2012, we contributed to Diamondback, prior to the closing of the Diamondback IPO, all of our oil and natural gas interests in the Permian Basin. At the closing of this contribution, Diamondback issued to us (i) 7,914,036 shares of Diamondback common stock and (ii) a promissory note for $63.6 million, which was repaid to us at the closing of the Diamondback IPO on October 17, 2012. This aggregate consideration was subject to a post-closing cash adjustment based on changes in the working capital, long-term debt and certain other items of a subsidiary of Diamondback as of the date of this contribution. In January 2013, we received an additional payment from Diamondback of $18.6 million as a result of this post-closing adjustment. As of October 23, 2012, following the closing of the Diamondback IPO and the underwriters' exercise in full of their option to purchase additional shares of common stock of Diamondback, we owned approximately 21.4% of Diamondback's outstanding common stock. Following the Contribution, we account for our interest in Diamondback as an equity investment.

Niobrara Formation (Northwestern Colorado)

Location and Land

Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in Northwestern Colorado, and held leases for approximately 11,788 net acres as of December 31, 2012. In 2012, three gross (one net) wells, including one gross (.04 net) well drilled by another operator, were spud on our Niobrara Formation acreage, two of which were completed as producers and one of which was non-productive.

Area History

The Niobrara Formation is a shale oil rock formation located in Colorado, Northwest Kansas, Southwest Nebraska, and Southeast Wyoming. Oil and natural gas can be found at depths of 3,000 to 14,000 feet and is drilled both vertically and horizontally. The Upper Cretaceous Niobrara Formation has emerged as another potential crude oil resource play in various basins throughout the northern Rocky Mountain region. As with most resource plays, the

Niobrara Formation has a history of

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producing through conventional technology with some of the earliest production dating back to the early 1900s. Natural fracturing has played a key role in producing the Niobrara Formation historically due to the low porosity and low permeability of the formation. Because of this, conventional production has been very localized and limited in area extent. We believe the Niobrara Formation can be produced on a more widespread basis using today's horizontal multi-stage fracture stimulation technology where the Niobrara Formation is thermally mature.

Geology

The Niobrara Formation oil play in Northwestern Colorado is located between the Piceance Basin to the south and the Sand Wash Basin to the north. Rocks mainly consist of interbedded organic-rich shales, calcareous shales and marlstones. It is the fractured marlstone intervals locally known as the Buck Peak, Tow Creek and Wolf Mountain benches that account for the majority of the areas production. These fractured carbonate reservoirs are associated with anticlinal, synclinal and monoclinal folds, and fault zones. This proven oil accumulation is considered to be continuous in nature and lightly explored. Source rocks are predominantly oil prone and thermally mature with respect oil generation. The producing intervals are geologically equivalent to the Niobrara Formation reservoirs of the DJ and Powder River Basins, which are currently emerging as a major crude resource play.

Production Status

In the fourth quarter of 2012, our net production from our Niobrara Formation acreage was approximately 2,644 BOE, or an average of 29 BOE per day, 100% of which was from oil. From January 1, 2013 through January 31, 2013, our average daily net production from our Niobrara Formation acreage was approximately 43 BOE, 100% of which was from oil.

Facilities

There are typical land oil and gas processing facilities in the Niobrara Formation. Our facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and Future Activity

We have completed a 60 square mile 3-D seismic survey over our Craig Dome prospect and have received a processed version of the seismic. We do not anticipate drilling any wells in the Niobrara Formation during 2013.

Bakken Formation

Location and Land

The Bakken Formation is located in the Williston Basin areas of Western North Dakota and Eastern Montana. During 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. The remaining interests in Bakken were owned by entities controlled by Wexford. Beginning in 2005, Bakken acquired leases on undeveloped acreage in the Williston Basin. As of December 31, 2007, Bakken had commenced participating in the drilling of some of its undeveloped acreage. Effective January 1, 2008, we acquired a direct, undivided 20% interest in Bakken's assets in redemption of our 20% interest in Bakken. During May 2009, we sold approximately 12,270 net acres and approximately 190 net BOE per day of production for approximately $13.0 million, with an effective date of April 1, 2009. During September 2009, we sold approximately 5,721 net acres for approximately $5.8 million with an effective date of July 1, 2009. As of December 31, 2012, we held approximately 864 net acres, interests in nine wells and an overriding royalty interests in certain existing and future wells.

Production Status

In the fourth quarter of 2012, our net production from our Bakken Formation acreage was approximately 7,355 BOE, or an average of 80 BOE per day, of which 87% was from oil, 3% was from NGLs and 10% was from natural gas. From January 1, 2013 through January 31, 2013, our average net daily production from this acreage was approximately 73 BOE, of which 89% was from oil and 11% was from natural gas.

Facilities

There are typical land oil and gas processing facilities in the Williston Basin. The facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

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Recent and Future Activities

Three gross (.04 net) wells were drilled on our Bakken Formation acreage in 2012. As of February 15, 2013, two gross (.03 net) wells had been drilled on our Bakken Formation acreage in 2013.

Additional Properties

Louisiana. In addition to our interests in the WCBB, East Hackberry and West Hackberry fields, we also own working interests and overriding royalty interest in various fields in Louisiana, Texas and Oklahoma as described in the following table as of December 31, 2012:

Field	State	Parish/County	Acreage Working Interest		Overriding Royalty Interests		Producing Wells	Non-Producing Wells
Deer Island	Louisiana	Terrebonne	3.125	%	—	%	1	—
Napoleonville	Louisiana	Assumption	—	%	2.5	%	3	—
Crest	Texas	Ochiltree	2	%	—	%	1	—
Eagle City South	Oklahoma	Dewey	1.04	%	—	%	1	—
Fay South	Oklahoma	Blaine	0.301	%	—	%	1	—
Squaw Cheek	Oklahoma	Blaine	0.694	%	—	%	1	—

Our Equity Investments

Permian Basin. As discussed above under the heading “-Recent Developments-Contribution,” on October 11, 2012, we contributed to Diamondback, prior to the closing of the Diamondback IPO, all of our oil and natural gas interests in the Permian Basin. At the closing of this contribution, Diamondback issued to us (i) 7,914,036 shares of Diamondback common stock and (ii) a promissory note for $63.6 million, which was repaid to us at the closing of the Diamondback IPO on October 17, 2012. This aggregate consideration was subject to a post-closing cash adjustment based on changes in the working capital, long-term debt and certain other items of a Diamondback subsidiary as of the date of this contribution. In January 2013, we received an additional payment from Diamondback of $18.6 million as a result of this post-closing adjustment. As of October 23, 2012, following the closing of the Diamondback IPO and the underwriters' exercise in full of their option to purchase additional shares of common stock of Diamondback, we owned approximately 21.4% of Diamondback's outstanding common stock. Our investment in Diamondback is accounted for as an equity method investment.

Grizzly Oil Sands. We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc., an entity owned by certain investment funds managed by Wexford. As of December 31, 2012, Grizzly had approximately 800,000 acres under lease in the Athabasca and Peace River oil sands region of Alberta, Canada. Our total net investment in Grizzly was approximately $172.8 million as of December 31, 2012. As of that date, Grizzly had drilled an aggregate of 233 core holes and six water supply test wells on ten separate lease blocks and conducted a number of seismic programs. In March 2010, Grizzly filed an application for the development of an 11,300 barrel per day oil sand project at Algar Lake. In November 2011, the Government of Alberta provided a formal Order in Council authorizing the ERCB to issue the formal regulatory approval of Grizzly's Algar Lake steam-assisted gravity drainage, or SAGD, project. Construction of the Algar Lake Phase 1 SAGD project commenced in 2012. During 2012, an 11 kilometer road was constructed to the project site, water and natural gas supply pipelines were installed, central plant modules were assembled, transported to the project site and lifted into place, ten production well pairs were drilled and completed and well pad modules and flow lines back to the central plant were installed. Grizzly expects first oil production at Algar Lake during the third quarter of 2013. In the first quarter of 2012, Grizzly completed the acquisition of the May River property comprising approximately 47,000 acres. In the fourth quarter of 2012, Grizzly initiated a 28 well core hole drilling program at May River and plans to file an initial 12,000 barrel per day development application with the ERCB by the end of 2013. At the Thickwood thermal project, Grizzly's 2012 activities included the completion of a 22 well core hole drilling program and the acquisition of 31 kilometers of seismic data. A development application for a 12,000 barrel per day oil sands project at Thickwood was filed in the fourth quarter of 2012. Grizzly anticipates approval of this development application in mid-2014 and first oil production by mid-2017. Grizzly has also entered into a memorandum of understanding that outlines the rate structure for a ten year agreement with Canadian National Railway Company, or CN, to transport its bitumen to the U.S. Gulf Coast via CN’s rail network. Grizzly expects that this arrangement will provide consistent access to Brent-based pricing from Grizzly’s Algar Lake project. Grizzly is also pursuing the design, permitting and construction of rail terminals in Northern Alberta and on the Lower Mississippi River, where it plans to develop scalable capacity to accommodate unit trains to ship and receive up to 100,000 barrels per day. Grizzly anticipates beginning to transport the company’s bitumen starting in the third quarter of 2013.

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Thailand. During 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II, at a cost of $2.4 million. The remaining interests in Tatex II are owned by entities controlled by Wexford. Tatex II, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 243,000 acres which includes the Phu Horm Field. During the year ended December 31, 2012, we received $0.8 million in distributions, reducing our total investment in Tatex II to $0.2 million. Our investment is accounted for on the equity method. Tatex II accounts for its investment in APICO using the cost method. In December 2006, first gas sales were achieved at the Phu Horm field located in northeast Thailand. Phu Horm's initial gross production was approximately 60 million cubic feet per day. For 2012, net gas production was approximately 93 MMcf per day and condensate production was 428 barrels per day. Hess Corporation, or Hess, operates the field with a 35% interest. Other interest owners include APICO (35% interest), PTT Exploration and Production Public Company Limited (20% interest) and ExxonMobil (10% interest). Our gross working interest (through Tatex II as a member of APICO) in the Phu Horm field is 0.7%. Since our ownership in the Phu Horm field is indirect and Tatex II's investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information.

During the first quarter of 2008, we purchased a 5% ownership interest in Tatex Thailand III, LLC, or Tatex III, at a cost of $850,000. In December 2009, we purchased an additional approximately 12.9% ownership interest at a cost of approximately $3.4 million bringing our total ownership interest to approximately 17.9%. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. Tatex III owns a concession covering approximately 490,000 acres in Southeast Asia. In 2009, Tatex III completed a 3-D seismic survey on this concession. During the year ended December 31, 2012, we paid $0.6 million in cash calls, bringing our total investment in Tatex III to $8.7 million. The first well was drilled on our concession in 2010 and was temporarily abandoned pending further scientific evaluation. Drilling of the second well concluded in March 2011. The second well was drilled to a depth of 15,026 feet and logged approximately 5,000 feet of apparent possible gas saturated column. The well experienced gas shows and carried a flare measuring up to 25 feet throughout drilling below the intermediate casing point of 9,695 feet. During testing, the well produced at rates as high as 16 MMcf per day of gas for short intervals, but would subsequently fall to a sustained rate of two MMcf per day of gas. Pressure buildup information confirmed that this wellbore lacked the permeability to deliver commercial quantities of gas. Despite an apparently well-developed porosity system suggesting potential for a large amount of gas in place, testing of the well did not exhibit that there was sufficient permeability to produce in commercial quantities. Tatex III intends to continue testing some of the structures identified through its 3-D seismic survey and has begun the application process for two more drilling locations. Tatex III currently expects to drill the first of these wells, located to the south of the TEW-E well, in 2013.

Other Investments. In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In the second quarter of 2012, we acquired a 50% equity interest in each of Stingray Pressure and Stingray Cementing. Stingray Pressure and Stingray Cementing will provide well completion services. We also acquired a 50% equity interest in Blackhawk, which coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage. In the fourth quarter of 2012, we also acquired a 50% equity interest in Stingray Logistics, which will provide well services. In March 2012, we acquired a 50% equity interest in Timber Wolf for $1.0 million. Also in March 2012, we acquired a 22.5% equity interest in Midstream for $7.0 million. Midstream owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011, we acquired a 25% equity interest in Bison, which owns and operates drilling rigs and related equipment. In April 2012, we purchased an additional 15% equity interest in Bison for approximately $6.2 million, bringing our total ownership interest in Bison to 40%. Also in 2011, we acquired a 25% interest in Muskie, which is engaged in the mining of hydraulic fracturing grade sand. The remaining equity interests in these entities are owned by affiliates of Wexford. In 2012, we invested approximately $42.8 million in these entities. In 2013, we expect to invest approximately $10.0 million to $15.0 million in these entities.

Competition and Markets

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 competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation. In addition, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

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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 demand for oil and natural gas and the level 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. The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production from WCBB is being sold in accordance with the Shell posted price for West Texas/New Mexico Intermediate crude plus or minus Platt's trade month average P+ value, plus or minus the Platt's HLS/WTI trade month average differential less $2.00 per barrel for transportation. During the year ended December 31, 2012, we sold approximately 92% and 8% of our oil production to Shell Trading Company, or Shell, and Diamondback O&G LLC (a wholly-owned subsidiary of Diamondback formerly known as Windsor Permian LLC), or Diamondback O&G, respectively, 91% of our natural gas liquids production to Diamondback O&G and 41%, 18% and 16% of our natural gas production to Noble Americas Gas, Hess and Chevron, respectively. During 2011, we sold 93% and 7% of our oil production to Shell and Diamondback O&G, respectively, 100% of our natural gas liquids production to Diamondback O&G, and 22%, 27% and 50% of our natural gas production to Diamondback O&G, Chevron and Hilcorp Energy Company, respectively. During 2010, we sold 75% and 19% of our oil production to Shell and Diamondback O&G, respectively, and 50%, 32%, and 10% of our natural gas production to Diamondback O&G, Chevron and Hilcorp Energy Company, respectively. Shell has agreed to purchase our Utica Shale oil and we have agreements in place with various purchasers for our Utica Shale natural gas production. We may not continue to have ready access to suitable markets for our future oil and natural gas production and 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.

Oil and natural gas prices can be extremely volatile and are subject to substantial seasonal, political and other fluctuations. The price at which the oil and natural gas we produce may be sold is uncertain and it is possible that under some market conditions the production and sale of oil and natural gas from some or all of our properties may not be economical. Because of all of the factors influencing the price of oil and natural gas, it is impossible to accurately predict future prices.

To mitigate the effects of commodity price fluctuations, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period January 2010 through February 2010. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through July 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from August 2012 through December 2012, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $107.29 per barrel. For the period from January 2013 through December 2013, we have entered into fixed price swaps for 5,000 barrels of oil per day at a weighted average price of $100.90 per barrel. Under the 2011 contracts, we hedged approximately 31% of our 2011 production. Under the 2012 contracts, we hedged approximately 46% of our 2012 production. Under the 2013 contracts, we have hedged approximately 23% of our estimated 2013 production. Such 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. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815, “Derivatives and Hedging,“ and related pronouncements.

Regulation

Regulation of Gas and Oil Production

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

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We own interests in a number of producing oil and natural gas properties located along the Louisiana Gulf Coast, and in the Utica Shale in Eastern Ohio, the Niobrara Formation in Northwestern Colorado and the Bakken Formation in Western North Dakota and Eastern Montana. The states in which our fields are located in regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields and the spacing and operation of wells. In addition, regulations governing conservation matters aimed at preventing the waste of oil and natural gas resources could affect the rate of production and may include maximum daily production allowables for wells on a market demand or conservation basis.

Environmental Regulation

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

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

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

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or the "Superfund" law, and analogous state laws, generally imposes strict and joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed "responsible parties" may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property

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

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

Air Emissions. The federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, on April 17, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new emission controls for oil and natural gas production and processing operations, which regulations are discussed in more detail under the caption “-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 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 pollutants” 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

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GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule, which purports to limit emissions of GHGs from motor vehicles manufactured in model years 2012-2016, in April 2010 and it became effective in January 2011, although it does not require immediate reductions in GHG emissions. A recent rulemaking proposal by the EPA and the Department of Transportation's National Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017-2025. The EPA adopted the stationary source rule, also known as the “Tailoring Rule,” in May 2010, and it also became effective in January 2011, although it remains subject of several pending lawsuits filed by industry groups. The Tailoring Rule establishes new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. The permitting requirements of the PSD program apply only to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the Tailoring Rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the Tailoring Rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the Tailoring Rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In addition, the EPA has continued to adopt GHG regulations of other industries, such as the March 2012 proposed GHG rule restricting future development of coal-fired power plants. The proposed rule underwent an extended public comment process, which concluded on June 25, 2012. The EPA is also under a legal obligation pursuant to a consent decree with certain environmental groups to issue new source performance standards for refineries. The EPA has also adopted regulations imposing best available control technology requirements on the largest greenhouse gas stationary sources, regulations requiring reporting of greenhouse gas emissions from certain facilities, and it is considering additional regulation of greenhouse gases as “air pollutants.” As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

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

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

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

Regulation of Hydraulic Fracturing

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

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

On April 17, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule 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 2013 and 2014. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities. The U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural-gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shale formations by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

Some states in which we operate or hold oil and natural gas interests 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. For example, in January 2012, the Ohio Department of Natural

Resources issued a temporary moratorium on the development of hydraulic fracturing disposal wells in northeast Ohio, to study the relationship between these wells and minor earthquakes reported in the area. The Texas Railroad Commission and Louisiana Department of Natural Resources recently adopted rules and regulations requiring that well operators disclose the list of chemical ingredients subject to the requirements of federal Occupational Safety and Health Act (OSHA) to state regulators and on a public internet website. Effective August 26, 2011, Montana adopted hydraulic fracturing disclosure regulations under which well operators must provide information in drilling permit applications on the estimated volume and types of materials to be used in the proposed hydraulic fracturing activities. Upon completion of the well, well operators must provide the Montana Board of Oil and Gas Conservation with the volume and type of chemicals used, including the additive type, chemical ingredient names, and Chemical Abstracts Service, or CAS, number, subject to certain trade secret protections. On April 1, 2012, the North Dakota

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Industrial Commission enacted regulations requiring hydraulic fracturing well operators to disclose the hydraulic fluid composition, including the trade name, supplier, ingredients, CAS Number, and the maximum ingredient concentrations of all additives in the hydraulic fracturing fluid. Colorado enacted rules requiring similar disclosures on January 30, 2012. Also, on May 4, 2012, the U.S. Department of Interior, or DOI, issued a draft rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm its wells meet certain construction standards and (iii) establish site plans to manage flowback water. We plan to use hydraulic fracturing 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 or offshore drilling, including legislation and regulation in the states in which we operate, could reduce the volumes of oil and gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

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

Other Regulation of the Oil and Natural Gas Industry

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

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

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

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

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or “allowables”;
- the surface use and restoration of properties upon which wells are drilled;

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- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

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

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

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

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

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

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

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

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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. The states in which we operate regulate the drilling for, and the production and gathering of, oil and natural gas, including through requirements relating to the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may also regulate rates of production and may establish maximum daily production allowables from wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

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

Operational Hazards and Insurance

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

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties for operational and hurricane related events. We currently have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of certain wells, oil pollution, third party liability, workers compensation and employers' liability and other coverage. 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 events could cause a significant disruption to our business. For example, we experienced production interruptions in 2005 and 2006 from Hurricanes Katrina and Rita and, in 2008, from Hurricanes Gustav and Ike. A loss not fully covered by insurance could have a material adverse affect on our financial position, results of operations and cash flows.

Currently, we have general liability insurance coverage with an annual aggregate limit of up to $21.0 million which includes environmental impairment coverage for the effects of onshore and offshore pollution on third parties arising from our operations. For our offshore WCBB properties, we also have a $25.0 million property physical damage policy which insures against most operational perils, such as explosions, fire, vandalism, theft, hail and windstorms, provided, however, that this policy is limited to $12.5 million for damages arising as a result of a named windstorm. In the event of a loss under this policy, we have up to $6.6 million of business interruption coverage available after a 90 day waiting period. All of our insurance coverage includes deductibles of up to $1,000,000 per occurrence ($1.5 million in the case of a named windstorm) that must be met prior to recovery. Additionally, our insurance is subject to customary exclusions and limitations. We reevaluate the purchase of insurance, policy terms and limits annually each May. 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.
At the depths and in the areas in which we operate, and in light of the vertical and directional drilling that we undertake, we typically do not encounter high pressures or extreme drilling conditions. Accordingly, we typically do not carry a control of well policy, although we currently have such coverage in place for five specific Southern Louisiana wells. In addition, it is currently anticipated that we will carry control of well coverage for all of our Utica Shale wells. We also require all of our third

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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.

We have prepared and have in place spill prevention control and countermeasure plans for each of our principal facilities at WCBB in response to federal and state requirements. The plans are reviewed annually and updated as necessary. As required by applicable regulations, our facilities are built with oil containment features and we own certain oil containment equipment, such as oil boom to surround drill sites and production facilities if needed. In addition, we have a national emergency response company on retainer. This company specializes in the clean up of hydrocarbons as a result of spills, blow-outs and natural disasters. This emergency response company has been involved in the clean up efforts of some of the largest oil spills along the Gulf Coast and is on call to us 24 hours a day when its services are needed. It has previously reported that it owns over 164 response vehicles, 65 response vessels, 116 response trailers equipped with decontaminant supplies, personal protective equipment and other equipment used in responding to oil spills, two storage barge sets, allowing for storage of up to 248 barrels of recovered oil each, and over 20 roll-off boxes and vacuum boxes. We pay this company a retainer plus additional amounts when it provides us with clean up services. Our aggregate payments for the retainer and clean up services during 2012 and 2011 were approximately $85,000 and $220,000, respectively. While this company has been able to meet our service needs when required from time to time in the past, it is possible that its ability to provide services to us in the future, if and when needed, could be hindered or delayed in the event of a widespread disaster. However, in light of the depths and the areas in which we operate, and the necessity for gas lift to produce our WCBB wells due to low reservoir pressure at our WCBB field, we believe other companies would be available to us in the event our primary remediation company was unable to perform.

Headquarters and Other Facilities

We own an approximately 28,500 square foot office building in Oklahoma City, Oklahoma that serves as our corporate headquarters. Additionally, we lease approximately 6,500 square feet of office space in other buildings in Oklahoma City. We also own an approximately 12,500 square foot building in Lafayette, Louisiana. This building contains approximately 6,200 square feet of finished office area and 6,300 square feet of clear span warehouse area. We also lease approximately 3,700 square feet in a building in Lafayette that we use as our Louisiana headquarters. We lease 1,400 square feet of office space in St. Clairsville, Ohio that serves as our Ohio headquarters. Each of these properties is suitable and adequate for its use.

Employees

At December 31, 2012, we had 128 employees. An unrelated Louisiana well servicing company provides all necessary field personnel needed to operate the WCBB and the Hackberry fields. During 2012, certain of our employees performed management and administrative services for affiliated companies for which we were reimbursed approximately $3.2 million.

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on the Investor Relations page of our website at www.gulfportenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information contained on our website, or on other websites that may be linked to our website, is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

ITEM 1A. RISK FACTORS

Risks Related to our Business and Industry

The volatility of oil and natural gas prices due to factors beyond our control greatly affects our profitability.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;
- the level of prices, and expectations about future prices, of oil and natural gas;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the expected rates of declining current production;

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- weather conditions, including hurricanes, and other natural disasters that can affect oil and natural gas operations over a wide area;
- the level of consumer demand;
- the price and availability of alternative fuels;
- technical advances affecting energy consumption;
- risks associated with operating drilling rigs;
- the availability of pipeline capacity and other transportation facilities;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the 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;
- political or economic instability or armed conflict in oil and natural gas producing regions, including the Middle East, Africa, South America and Russia; and
- the overall domestic and global economic environment.

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 herein 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 MMBtu in September 2009 to a high of $13.31 per MMBtu in July 2008. During 2012, West Texas Intermediate prices ranged from $80.48 to $108.99 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.80 to $3.80 per MMBtu. On December 31, 2012, the West Texas Intermediate posted price for crude oil was $91.82 per barrel and the Henry Hub spot market price of natural gas was $3.35 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.

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

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

Our success depends on finding, developing or acquiring additional reserves, which requires significant capital expenditures.

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. Historically, we have financed capital expenditures primarily with cash flow from operations, the issuance of equity securities and borrowings under our bank and other credit facilities. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level 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 may not have sufficient resources to acquire additional reserves or to undertake exploration, development, production or other replacement activities, such activities may not result in significant additional reserves and we may not have success drilling productive wells at low finding and development costs. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

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

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

If we are unable to complete capital projects in a timely manner, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Delays related to capital spending programs involving engineering, procurement and construction of facilities (including improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted internal rates of return and operating results. Delays in making required changes or upgrades to our facilities could subject us to fines or penalties as well as affect our ability to supply certain products we produce. Such delays may arise as a result of unpredictable factors, many of which are beyond our control, including:

- denial of or delay in receiving requisite regulatory approvals and/or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of components or construction materials;
- adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of vendors or suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project's debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors or subcontractors.

Any one or more of these factors could have a significant impact on our ongoing capital projects.

Our Canadian oil sands projects are complex undertakings and may not be completed at our estimated cost or at all.

We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. The remaining interest in Grizzly is owned by Grizzly Oils Sands Inc., an entity owned by certain investment funds managed by Wexford. As of December 31, 2012, Grizzly had approximately 800,000 acres under lease in the Athabasca and Peace

River oil sands regions of Alberta, Canada. Our total net investment in Grizzly was approximately $172.8 million as of December 31, 2012. As of that date, Grizzly had drilled an aggregate of 233 core holes and six water supply test wells on ten separate lease blocks and conducted a number of seismic programs. In March 2010, Grizzly filed an application for the development of an 11,300 barrel per day oil sand project at Algar Lake. In November 2011, the Government of Alberta provided a formal Order in Council authorizing the ERCB to issue the formal regulatory approval of Grizzly's Algar Lake steam-assisted gravity drainage, or SAGD, project. Construction of the Algar Lake Phase 1 SAGD project commenced in 2012. During 2012, an 11 kilometer

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road was constructed to the project site, water and natural gas supply pipelines were installed, central plant modules were assembled, transported to the project site and lifted into place, ten production well pairs were drilled and completed and well pad modules and flow lines back to the central plant were installed. Grizzly expects first oil production at Algar Lake during the third quarter of 2013. In the first quarter of 2012, Grizzly completed the acquisition of the May River property comprising approximately 47,000 acres. In the fourth quarter of 2012, Grizzly initiated a 28 well core hole drilling program at May River and plans to file an initial 12,000 barrel per day development application with the ERCB by the end of 2013. At the Thickwood thermal project, Grizzly's 2012 activities included the completion of a 22 well core hole drilling program and the acquisition of 31 kilometers of seismic data. A development application for a 12,000 barrel per day oil sands project at Thickwood was filed in the fourth quarter of 2012. Grizzly anticipates approval of this development application in mid- 2014 and first oil production by mid-2017. Grizzly has also entered into a memorandum of understanding that outlines the rate structure for a ten year agreement with Canadian National Railway Company, or CN, to transport its bitumen to the U.S. Gulf Coast via CN's rail network. Grizzly expects that this arrangement will provide consistent access to Brent-based pricing from Grizzly's Algar Lake project. Grizzly is also pursuing the design, permitting and construction of rail terminals in Northern Alberta and on the Lower Mississippi River, where it plans to develop scalable capacity to accommodate unit trains to ship and receive up to 100,000 barrels per day. Grizzly anticipates beginning to transport the company's bitumen starting in the third quarter of 2013. These are complex projects and additional financing may be required. There can be no assurance that such financing, if required, could be obtained on commercially reasonable terms or at all.

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. 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.

We rely on a few key employees whose absence or loss could disrupt our operations resulting in a loss of revenues.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services, particularly the loss of Mike Liddell, our Chairman of the Board, James D. Palm, our Chief Executive Officer, Michael G. Moore, our Chief Financial Officer, or our two geophysicists could disrupt our operations resulting in a loss of revenues. Our executives are not restricted from competing with us if they cease to be employed by us, except under certain limited circumstances prohibiting competition while making use of our trade secrets. We are party to an employment agreement with each of these executive officers. As a practical matter, however, 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.

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.

Estimates of oil and natural gas reserves are uncertain and may vary substantially from actual production.

There are numerous uncertainties associated with estimating quantities of proved reserves and in projecting future rates of production and timing of expenditures. The reserve information herein represents estimates prepared by (i) Netherland, Sewell & Associates, Inc., or NSAI, with respect to our WCBB, Hackberry and Niobrara fields at each of December 31, 2012 and 2011 and with respect to our WCBB and Niobrara fields at December 31, 2010, (ii) Ryder Scott with respect to our Utica Shale acreage at December 31, 2012 and our Permian Basin acreage at December 31, 2011 and (iii) Pinnacle Energy Services, LLC,

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or Pinnacle, with respect to our Permian Basin acreage at December 31, 2010 (which acreage has been contributed to Diamondback as described in Item 1. "Business-Recent Developments-Contribution") and (iv) our personnel with respect to our overriding royalty and non-operated interests at December 31, 2012 and 2011 and with respect to our Hackberry fields, overriding royalty and non-operated interests at December 31, 2010. Petroleum engineering is not an exact science. Information relating to our proved oil and natural gas reserves is based upon engineering estimates. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, future site restoration and abandonment costs, the assumed effects of regulations by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, capital expenditures and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Estimates of reserves as of year-end 2012, 2011 and 2010 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2012, 2011 and 2010, respectively, in accordance with the revised guidelines of the SEC applicable to reserves estimates for such years. 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.

The present value of future net revenues from our proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves. We base the estimated discounted future net revenue from our proved reserves for 2012, 2011 and 2010 on an average price equal to the unweighted arithmetic average of prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2012, 2011 and 2010, respectively, in accordance with the revised guidelines of the SEC applicable to reserves estimates for such years. However, actual future net revenues from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

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 revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

As of December 31, 2012, approximately 40.2% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and may require successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but these assumptions may not be accurate, and this may not occur.

There are numerous uncertainties in estimating quantities of bitumen reserves and resources in connection with our equity investment in Grizzly and the indicated level of reserves or recovery of bitumen may not be realized.

There are numerous uncertainties in estimating quantities of bitumen reserves and resources, and the indicated level of reserves or recovery of bitumen may not be realized. In general, estimates of economically recoverable bitumen reserves and the future net cash flow from such reserves are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

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Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history may result in variations in the estimated reserves. Reserve and resource estimates may require revision based on actual production experience. Reserve and resources estimates are determined with reference to assumed oil prices and operating costs. Market price fluctuations of oil prices may render uneconomic the recovery of certain grades of bitumen. The actual gravity or quality of bitumen to be produced from Grizzly's lands cannot be determined at this time.

The marketability of our production is dependent upon compressors, gathering lines, transportation barges 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 natural gas lines and transportation barges owned by third parties. In general, we do not control these transportation facilities and our access to them may be limited or denied. A significant disruption in the availability of these transportation facilities or our compression and 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. We are at particular risk with respect to oil and natural gas produced at our WCBB field, which is our largest producing field. In October 2006, for example, a natural gas line in this field operated by our natural gas purchaser was ruptured by a third party contractor, requiring the field to be shut in for approximately seven weeks until the line could be repaired. Further, we are dependent on our oil purchaser to provide the barges necessary to transport our oil production from the WCBB field. In addition, we currently intend to focus a significant portion of our future exploration and development activity on our Utica Shale acreage. Historically, there has been no or only limited infrastructure in this area and the commencement of production from our initial wells on our Utica Shale acreage has been delayed due to challenges in obtaining rights-of-way and acquiring necessary state and federal permitting. If we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter compression or other production related difficulties, we will be required to shut in or curtail production from the impacted field(s). Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would adversely affect our financial condition and results of operations.

A substantial portion of our producing properties is located in Louisiana, making us vulnerable to risks associated with operating in this region.

Our largest field by production, WCBB, is located approximately five miles off the coast of Louisiana in a shallow bay with water depths averaging eight to ten feet. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from this region caused by weather conditions such as fog or rain, hurricanes or other natural disasters or lack of field infrastructure. Losses could occur for uninsured risks or in amounts in excess of any existing insurance coverage. We may not be able to obtain and maintain adequate insurance at rates we consider reasonable or that any particular types of coverage will be available.

Our identified 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.

We have identified over 700 drilling locations on our Louisiana, Ohio and Western Colorado properties. These drilling locations 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, oil and natural gas prices, inclement weather, costs, drilling results and regulatory changes. Because of these uncertainties, we do not know if the numerous 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.

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

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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.

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

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

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 understand that insurance carriers are modifying or otherwise restricting insurance coverage or ceasing to provide certain types of insurance coverage in the Gulf Coast region. 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. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

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

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

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

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

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

Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and expected future market prices for oil and natural gas, expected costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost. Drilling results in our newer oil and liquids-rich shale plays may be more uncertain than in shale plays that are more developed and have longer established production histories, and we can provide no assurance that drilling and completion techniques that have proven to be successful in other shale formations to maximize recoveries will be ultimately successful when used in newly developed shale formations.

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

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas 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.

We are not the operator of all of our oil and natural gas properties and therefore are not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

We are not the operator of all of the properties in which we have an interest, and have limited ability to exercise influence over the operations of such non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs, could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others will depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;

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- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of the reserves.

In addition, when we are not the majority owner or operator of a particular oil or natural gas project, if we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As of December 31, 2012, leases representing 45%, 17%, 2%, 12% and 24%, respectively, of our total Niobrara Formation undeveloped acreage are scheduled to expire in 2013, 2014, 2015, 2016 and thereafter. None of our Utica Shale acreage leases are scheduled to expire until 2015, at which time 36% of our total Utica Shale undeveloped acreage as of December 31, 2012 will be subject to expiration, with 64% of such acreage expiring thereafter, although our Utica Shale leases generally grant us the right to extend these leases for an additional five-year period. 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 differ materially from our current expectations, which could adversely affect our business.

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

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

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

Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations, requirements for additional pollution controls and injunctions limiting or prohibiting some or all of our operations. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. See Item 1. "Business-Regulations-Environmental Matters and Regulation" and Item 1. "Business-Regulation-Other Regulation of The Oil and Natural Gas Industry" for a description of the laws and regulations that affect us.

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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 White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices and the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

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

On April 17, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules will require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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

Some states in which we operate or hold oil and natural gas interests 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. For example, in January 2012, the Ohio Department of Natural Resources issued a temporary moratorium on the development of hydraulic fracturing disposal wells in northeast Ohio, to study the relationship between these wells and minor earthquakes reported in the area. The Texas Railroad Commission and Louisiana Department of Natural Resources recently adopted rules and regulations requiring that well operators disclose the list of chemical ingredients subject to the requirements of federal Occupational Safety and Health Act (OSHA) to state regulators and on a public internet website. Effective August 26, 2011, Montana adopted hydraulic fracturing disclosure regulations under which well operators must provide information in drilling permit applications on the estimated volume and types of materials to be used in the proposed hydraulic fracturing activities. Upon completion of the well, well operators must provide the Montana Board of Oil and Gas

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Conservation with the volume and type of chemicals used, including the additive type, chemical ingredient names, and Chemical Abstracts Service, or CAS, number, subject to certain trade secret protections. On April 1, 2012, the North Dakota Industrial Commission enacted regulations requiring hydraulic fracturing well operators to disclose the hydraulic fluid composition, including the trade name, supplier, ingredients, CAS Number, and the maximum ingredient concentrations of all additives in the hydraulic fracturing fluid. Colorado enacted rules requiring similar disclosures on January 30, 2012. Also, on May 4, 2012, the U.S. Department of Interior, or DOI, issued a draft rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm its wells meet certain construction standards and (iii) establish site plans to manage flowback water. We plan to use hydraulic fracturing 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 or offshore drilling, including legislation and regulation in the states in which we operate, could reduce the volumes of oil and gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

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

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

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development and production activities. These laws and regulations may, among other things: (i) require us to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, producing and other operations; (ii) regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; (iii) limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; (iv) require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or (v) impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, the risk of accidental and/or unpermitted spills or releases from our operations could expose us to significant liabilities, penalties and other sanctions under applicable laws. In this regard, in November 2012, we and other entities involved in our WCBB field operations received a government subpoena, to which we have responded, for the production of documents and other information related primarily to a discharge of produced water that allegedly was identified by the U.S. Coast Guard in March 2012. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

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

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

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

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The U.S. Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation was signed into law by the President on July 21, 2010. In its rulemaking under the legislation, the Commodities Futures Trading Commission, or the CFTC, has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions). The CFTC's final rule was set aside by the U.S. District Court for the District of Columbia on September 28, 2012 and remanded to the CFTC to resolve ambiguity as to whether statutory requirements for such limits to be determined necessary and appropriate were satisfied. As a result, the rule has not yet taken effect, although the CFTC has indicated that it intends to appeal the court's decision and that it believes the Dodd-Frank Act requires it to impose position limits. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions. In addition, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirement to use cleared exchanges, rather than hedging over-the-counter, and the requirements to post margin in connection with hedging activities. While it is not possible at this time to predict when the CFTC will finalize certain other related rules and regulations, the Dodd-Frank Act and related regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, our hedging would become more expensive and we may decide to alter our hedging strategy.

The financial reform legislation may also require 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.

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

The U.S. President's Fiscal Year 2013 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws. These changes include, but are not limited to, (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, (iii) the repeal of the percentage depletion allowance for oil and gas properties, (iv) an extension of the amortization period for certain geological and geophysical expenditures and (iv) implementing certain international tax reforms. These proposed changes in the U.S. tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

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

Many nations have agreed to limit emissions of "greenhouse gases" pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are "greenhouse gases," or GHGs, regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol at this time, several states or geographic regions have adopted legislation and regulations to reduce emissions of greenhouse gases. Additionally, on April 2, 2007, the U.S. Supreme Court ruled, in Massachusetts, et al. v. EPA, that the EPA has the authority to regulate carbon dioxide emissions from automobiles as "air pollutant" under the federal Clean Air Act. Thereafter, in December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule, which purports to limit emissions of GHGs from motor vehicles manufactured in model years 2012-2016, in April 2010 and it became effective in January 2011, although it does not require immediate reductions in GHG emissions. A recent rulemaking proposal by the EPA and the Department of Transportation's National Highway Traffic Safety Administration seeks to expand the motor vehicle rule to include vehicles manufactured in model years 2017-2025. The EPA adopted the stationary source rule, also known as the "Tailoring Rule," in May 2010, and it also became effective in January 2011, although it remains subject of several pending lawsuits filed by industry groups. The Tailoring Rule establishes new GHG emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. The permitting requirements of the PSD program apply only to newly constructed or modified major sources. Obtaining a PSD permit requires a source to install best available control technology, or BACT, for those regulated pollutants that are emitted in certain quantities. Phase I of the Tailoring Rule, which became effective on January 2, 2011, requires projects already triggering PSD permitting that are also increasing GHG emissions by more than 75,000 tons per year to comply with BACT rules for their GHG emissions. Phase II of the Tailoring Rule, which became effective on July 1, 2011, requires preconstruction permits using BACT for new projects that emit 100,000 tons of GHG emissions per year or existing facilities that make major modifications increasing GHG emissions by more than 75,000 tons per year. Phase III of the Tailoring Rule, which is expected to go into effect in 2013, will seek to streamline the permitting process and permanently exclude smaller sources from the permitting process. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in

2010. In November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In addition, the EPA has continued to adopt GHG regulations of other industries, such as the March 2012 proposed GHG rule restricting future development of coal-fired power plants. The proposed rule underwent an extended public comment process, which concluded on June 25, 2012. The EPA is also under a legal obligation pursuant to a consent decree with certain environmental groups to issue new source performance standards for refineries. The EPA has also adopted regulations imposing best available control technology requirements on the largest greenhouse gas stationary sources, regulations requiring reporting of greenhouse gas emissions from certain facilities, and it is considering additional regulation of greenhouse gases as “air pollutants.” As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

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

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 face extensive competition in our industry.

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 competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

We depend upon a limited number of customers 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. The oil and natural gas we produce in

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Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production from WCBB is being sold in accordance with the Shell posted price for West Texas/New Mexico Intermediate crude plus or minus Platt's trade month average P+ value, plus or minus the Platt's HLS/WTI differential less $2.00 per barrel for transportation. During the year ended December 31, 2012, we sold approximately 92% and 8% of our oil production to Shell and Diamondback O&G, respectively, 91% of our natural gas liquids production to Diamondback O&G, and 41%, 18% and 16% of our natural gas production to Noble Americas Gas, Hess and Chevron, respectively. During 2011, we sold 93% and 7% of our oil production to Shell and Diamondback O&G, respectively, 100% of our natural gas liquids production to Diamondback O&G and 22%, 27% and 50% of our natural gas production to Diamondback O&G, Chevron and Hilcorp Energy Company, respectively. During 2010, we sold 75% and 19% of our oil production to Shell and Diamondback O&G, respectively, and 50%, 32%, and 10% of our natural gas production to Diamondback O&G, Chevron and Hilcorp Energy Company, respectively. Shell has agreed to purchase our Utica oil, and we have agreements in place with various purchasers for our Utica natural gas production. We may not continue to have ready access to suitable markets for our future oil and natural gas production.

Our method of accounting for oil and natural gas properties may result in impairment of asset value.

We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proven oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil.

Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted arithmetic average of the first-day-of-the-month prices for 2012, 2011 and 2010 adjusted for any contract provisions or financial derivatives, if any, that hedge oil and natural gas revenue, excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash writedown is required. A ceiling test impairment can give us a significant loss for a particular period. Once incurred, a write down of oil and natural gas properties is not reversible at a later date, even if oil or gas prices increase. If prices of oil, natural gas and natural gas liquids decrease, we may be required to further write down the value of our oil and gas properties. Future non-cash asset impairments could negatively affect our results of operations.

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 have entered into forward sales contracts and fixed price swaps and may in the future enter into additional contracts 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.

To mitigate the effects of commodity price fluctuations, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period January 2010 through February 2010. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel for the period January 2011 through December 2011. For

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January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through July 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from August 2012 through December 2012, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $107.29 per barrel. For the period from January 2013 through December 2013, we have entered into fixed price swaps for 5,000 barrels of oil per day at a weighted average price of $100.90 per barrel. Under the 2011 contracts, we hedged approximately 31% of our 2011 production. Under the 2012 contracts, we hedged approximately 46% of our 2012 production. Under the 2013 contracts, we have hedged approximately 23% of our estimated 2013 production. Such 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. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815, "Derivatives and Hedging," and related pronouncements.

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.

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.

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.

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

We are 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.

Risks Relating to Our Indebtedness

Our substantial level of indebtedness could adversely affect our business, financial condition, results of operations and prospects.

As of December 31, 2012, we had total indebtedness (net of associated accrued discount and premium) of approximately $299.0 million, including $296.9 million attributable to the Notes, and borrowing base availability of $40.0 million under our secured revolving credit facility, under which no borrowings are outstanding.

Our outstanding indebtedness could have important consequences to you, including the following:

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- our high level of indebtedness could make it more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations under any of our debt instruments, including restrictive covenants, could result in a default under our secured revolving credit facility or the senior note indenture;
- the restrictions imposed on the operation of our business by the terms of our debt agreements may hinder our ability to take advantage of strategic opportunities to grow our business;
- our ability to obtain additional financing for working capital, capital expenditures, debt service requirements, restructuring, acquisitions or general corporate purposes may be impaired, which could be exacerbated by further volatility in the credit markets;
- we must use a substantial portion of our cash flow from operations to pay interest on the Notes and our other indebtedness, which will reduce the funds available to us for operations and other purposes;
- our high level of indebtedness could place us at a competitive disadvantage compared to our competitors that may have proportionately less debt;
- our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate may be limited;
- our high level of indebtedness makes us more vulnerable to economic downturns and adverse developments in our business; and
- we may be vulnerable to interest rate increases, as our borrowings under our secured revolving credit facility are at variable interest rates.

Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations and prospects.

In addition, if we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, or interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest. More specifically, the lenders under our secured revolving credit facility could elect to terminate their commitments, cease making further loans and institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or litigation.

We may not have sufficient funds to repay borrowings under our revolving credit facility if required as a result of a borrowing base redetermination.

In connection with the Contribution and the Notes Offerings, our borrowing base under our senior secured revolving credit facility was reduced to $40.0 million. The borrowing base is expected to be redetermined by the lenders on a semiannual basis. Additionally, the required lenders will be able to request one additional borrowing base redetermination in between scheduled redeterminations, and also have the right to redetermine the borrowing base upon the amendment, modification or termination of any swap contract or forward sales contract. In addition, our borrowing base will be reduced in connection with certain asset dispositions.

We repaid all borrowings outstanding under our secured revolving credit facility (approximately $146.5 million) with a portion of the proceeds from the October Notes Offering. We currently have no borrowings outstanding under our revolving credit facility, although we intend to reborrow under this facility in the future. If the outstanding borrowings under our secured revolving credit facility were to exceed the borrowing base as a result of any such recalculation, we would be required to eliminate this excess. If we are forced to repay a portion of our bank borrowings, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Servicing our indebtedness requires a significant amount of cash, and we may not have sufficient cash flow from our business to pay our substantial indebtedness.

Our ability to make scheduled payments of the principal of, to pay interest on or to refinance our indebtedness depends on our future performance, which is subject to economic, financial, competitive and other factors beyond our control. Our business may not continue to generate cash flow from operations in the future sufficient to service our debt and make necessary capital expenditures. If we are unable to generate such cash flow, we may be required to adopt one or more alternatives, such as reducing or delaying capital expenditures, selling assets, restructuring debt or obtaining additional equity capital on terms that may be onerous or highly dilutive. In the absence of such cash flows, we could have substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our secured revolving credit facility and the senior note indenture restrict our ability to use the proceeds from asset sales. We may not be able to consummate those asset sales to raise capital or sell assets at prices that we believe are fair, and proceeds that we do receive may not be adequate to meet any debt service obligations then due. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at the time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations and have an adverse effect on our financial condition.

Despite our current leverage, we may still be able to incur substantially more indebtedness. This could further exacerbate the risks that we and our subsidiaries face.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future, either under our senior secured credit facility or otherwise. The terms of our secured revolving credit facility and the indenture governing the Notes restrict our ability to incur additional indebtedness, but in each case do not completely prohibit us from doing so. In addition, the indenture governing the Notes allows us to issue additional notes under certain circumstances which will also be guaranteed by the guarantors. The indenture governing the Notes allows us to incur certain other additional secured debt and will allow our subsidiaries that do not guarantee the Notes to incur additional debt. In addition, the indenture governing the Notes does not prevent us from incurring other liabilities that do not constitute indebtedness. If new debt or other liabilities are added to our current debt levels, the related risks that we and our subsidiaries now face could intensify.

Restrictive covenants in our secured revolving credit facility, in the senior note indenture and in future debt instruments may restrict our ability to pursue our business strategies.

Our secured revolving credit facility and the senior note indenture limit, and the terms of any future indebtedness may limit, our ability, among other things, to:

- incur or guarantee additional indebtedness;
- make certain investments;
- declare or pay dividends or make distributions on our capital stock;
- prepay subordinated indebtedness;
- sell assets including capital stock of restricted subsidiaries;
- agree to payment restrictions affecting our restricted subsidiaries;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets;
- enter into transactions with our affiliates;
- incur liens;
- engage in business other than the oil and gas business; and
- designate certain of our subsidiaries as unrestricted subsidiaries.

The restrictions contained in these agreements could limit our ability to plan for, or react to, market conditions, meet capital needs, make acquisitions or otherwise restrict our activities or business plans.

A breach of any of these restrictive covenants could result in default under the agreement governing our senior secured revolving credit facility. If default occurs, the lenders under our senior secured revolving credit facility may elect to declare all borrowings outstanding, together with accrued interest and other fees, to be immediately due and payable, which would result in an event of default under the senior note indenture. The lenders will also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If we are unable to repay outstanding borrowings when due, the lenders under our senior secured revolving credit facility will also have the right to proceed against the collateral granted to them to secure the indebtedness. If the indebtedness under our senior secured revolving credit facility and the Notes were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full that indebtedness.

Risks Related to Our Common Stock

If our quarterly revenues and operating results fluctuate significantly, the price of our common stock may be volatile.
Our revenues and operating results may in the future vary significantly from quarter to quarter. If our quarterly results fluctuate, it may cause our stock price to be volatile. We believe that a number of factors could cause these fluctuations, including:

- changes in oil and natural gas prices;
- changes in production levels;
- changes in governmental regulations and taxes;
- geopolitical developments;
- the level of foreign imports of oil and natural gas; and
- conditions in the oil and natural gas industry and the overall economic environment.

Because of the factors listed above, among others, we believe that our quarterly revenues, expenses and operating results may vary significantly in the future and that period-to-period comparisons of our operating results are not necessarily meaningful. You should not rely on the results of one quarter as an indication of our future performance. It is also possible that in some future quarters, our operating results will fall below our expectations or the expectations of market analysts and investors. If we do not meet these expectations, the price of our common stock may decline significantly.

We do not currently pay dividends on our common stock and do not anticipate doing so in the future.

We have paid no cash dividends on our common stock, and we may not pay cash dividends on our common stock in the future. We intend to retain any earnings to fund our operations. Therefore, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. In addition, the terms of our credit agreement prohibit the payment of any dividends to the holders of our common stock.

A change of control could limit our use of net operating losses.

As of December 31, 2012, we had a net operating loss, or NOL, carry forward of approximately $4.3 million for federal income tax purposes. Transfers of our stock in the future could result in an ownership change. In such a case, our ability to use the NOLs generated through the ownership change date could be limited. In general, the amount of NOLs we could use for any tax year after the date of the ownership change would be limited to the value of our stock (as of the ownership change date) multiplied by the long-term tax-exempt rate.

Future sales of our common stock may depress our stock price.

We have registered a substantial number of shares of our common stock under a registration statement filed with the SEC. Sales of these shares of our common stock in the public market or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, sales by certain of our stockholders of their shares could impair our ability to raise capital through the sale of common or preferred stock. As of February 20, 2013, there were 77,339,886 shares of our common stock issued and outstanding, excluding 245,831 shares of unvested restricted stock awarded under our Amended and Restated 2005 Stock Incentive Plan and 335,241 shares issuable upon exercise of outstanding options to purchase our common stock granted under our Amended and Restated 2005 Stock Incentive Plan.

We could issue preferred stock which could be entitled to dividend, liquidation and other special rights and preferences not shared by holders of our common stock or which could have anti-takeover effects.

We are authorized to issue up to 5,000,000 shares of preferred stock, par value $0.01 per share. Shares of preferred stock may be issued from time to time in one or more series as our board of directors, by resolution or resolutions, may from time to time determine each such series to be distinctively designated. The voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations or restrictions, if any, of each such series of preferred stock may differ from those of any and all other series of preferred stock at any time outstanding, and, subject to certain limitations of our certificate of incorporation and the Delaware General Corporation Law, or DGCL, our board of directors may fix or alter, by resolution or resolutions, the designation, number, voting powers, preferences and relative, participating, optional and other special rights, and qualifications, limitations and restrictions thereof, of each such series preferred stock. The issuance of any such preferred stock could materially adversely affect the rights of holders of our common stock and, therefore, could reduce the value of our common stock.

In addition, specific rights granted to future holders of preferred stock could be used to restrict our ability to merge with, or sell our assets to, a third party. The ability of our board of directors to issue preferred stock could discourage, delay or prevent a takeover of us, thereby preserving control of the company by the current stockholders.

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The existence of some provisions in our organizational documents 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Additional information regarding our properties is included in Item 1. "Business" above and in Note 4 of the notes to our consolidated financial statements included in this report, which information is incorporated herein by reference.

Proved Oil and Natural Gas 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.

Reserve estimates at December 31, 2012 were prepared by NSAI with respect to our WCBB, Hackberry and Niobrara fields (52% of our proved reserves at December 31, 2012), by Ryder Scott with respect to our assets in the Utica Shale in Eastern Ohio (47% of our proved reserves at December 31, 2012) and by our personnel with respect to our overriding royalty and non-operated interests (less than 1% of our proved reserves at December 31, 2012).

NSAI and Ryder Scott are independent petroleum engineering firms. Copies of their summary reserve reports are included as Exhibit 99.1 and 99.2, respectively, to this Annual Report on Form 10-K. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with NSAI and Ryder Scott, our independent reserve engineers, to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our WCBB, Hackberry and Niobrara fields and our assets in the Utica Shale. Our internal technical team members meet with NSAI and Ryder Scott periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to NSAI and Ryder Scott for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Our proved reserves attributable to our other minority interests are prepared internally by our internal staff of petroleum engineers and geoscience professionals. Our chief reserve engineer is primarily responsible for overseeing the preparation of all of our reserve estimates. He is a petroleum engineer with over 30 years of reservoir and operations experience and our geophysical staff has

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over 60 years combined industry experience. 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. Our proved reserve estimates are prepared 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 experienced reservoir engineers or under their direct supervision;
- review by our reservoir engineering department 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 reservoir engineering department to our Chief Executive Officer; and
- verification of property ownership by our land department.

The following table sets forth our estimated proved reserves at December 31, 2012, 2011 and 2010:

	Year Ended December 31,					
	2012		2011		2010	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved developed	5,219	18,482	7,485	6,152	7,230	6,068
Proved undeveloped	3,032	15,289	9,260	9,576	12,474	10,090
Total (1)	8,251	33,771	16,745	15,728	19,704	16,158

	Year Ended December 31,		
	2012	2011	2010
Total net proved oil and natural gas reserves (MBOE) (1)	13,879	19,367	22,397
PV-10 value (in millions) (2)	$436.8	$490.5	$392.6
Standardized measure (in millions) (3)	$348.6	$376.7	$315.5

(1) Estimates of reserves as of year-end 2012, 2011 and 2010 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2012, 2011 and 2010, respectively, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2012, 2011 and 2010. 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.

(2) Represents present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proven reserves. The estimated future net revenues set forth above were determined by using reserve quantities of proved reserves and the periods in which they are expected to be developed and produced based on certain prevailing economic conditions. The estimated future production in our reserve reports for the years ended December 31, 2012, 2011 and 2010 is priced based on the 12-month unweighted arithmetic average of the first-day-of-the month price for the period January through December of the applicable year, using $91.32 per barrel and $2.76 per MMBtu for 2012, $96.19 per barrel and $4.12 per MMBtu for 2011 and $76.16 per barrel and $4.38 per MMBtu for 2010, and in each case adjusted by lease for transportation fees and regional price differentials.

PV-10 is a non-GAAP measure because it excludes income tax effects. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. PV-10 is not a measure of financial or operating performance under GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of PV-10 to the most directly comparable GAAP measure-standardized measure of discounted future net cash flows. The following table reconciles the standardized measure of future net cash flows to the PV-10 value:

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	December 31,		
	2012	2011	2010
Standardized measure of discounted future net cash flows	$348,641,000	$376,681,000	$315,487,000
Add: Present value of future income tax discounted at 10%	88,206,000	113,791,000	77,117,000
PV-10 value	$436,847,000	$490,472,000	$392,604,000

(3) The standardized measure represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

The above table does not include proved reserves net to our interest in Diamondback, Tatex II, Tatex III or Grizzly. For further discussion of our interest in Tatex II, Tatex III and Grizzly, see Item 1. “Business-Our Equity Investments.”
The foregoing reserves are all located within the continental United States. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See Item 1A. “Risk Factors” contained elsewhere in this Form 10-K. We have not filed any estimates of total, proved net oil or gas reserves with any federal authority or agency other than the SEC since the beginning of our last fiscal year.

Additional information regarding estimates of proved reserves, proved developed reserves and proved undeveloped reserves, or PUDs, at December 31, 2012, 2011 and 2010 and changes in proved reserves during the last three years are contained in the Supplemental Information on Oil and Gas Exploration and Production Activities, or Supplemental Information, in Note 18 to our consolidated financial statements included in this report. Also contained in the Supplemental Information are our estimates of future net cash flows and discounted future net cash flows from proved reserves. Additional information regarding our proved reserves can be found in Item 7. “Management's Discussion and Analysis of Financial Condition and Results of Operations-Results of Operations” and “-Critical Accounting Policies and Estimates” included in this report.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2012, our proved undeveloped reserves totaled 3,032 MBOE of oil and 15,289 MMcf of natural gas, for a total of 5,580 MBOE. Approximately 61% of our PUDs at year-end 2012 were located in our Utica field, 21% were located in WCBB, 17% were located in our East Hackberry field and 1% of our PUDs were located in our Niobrara field. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

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

- The loss of approximately 9,574 MBOE attributable to the contribution of our Permian Basin acreage to Diamondback;
- Additions of 3,376 MBOE attributable to 2012 acquisitions and extensions in our Utica field and additions of 1,275 MBOE attributable to 2012 extensions in our Louisiana fields;
- Conversion of approximately 73 MBOE attributable to PUDs into proved developed reserves;
- Downward revisions of approximately 31 MBOE in PUDs due to changes in commodity prices;
- Downward revisions to estimates of approximately 215 MBOE; and
- Exclusion of 34 MBOE attributable to one PUD location that was not scheduled to be drilled within the next five years.

Costs incurred relating to the development of PUDs were approximately $18.0 million in 2012. Estimated future development costs relating to the development of PUDs are projected to be approximately $82.8 million in 2013, $16.4 million in 2014, $4.3 million in 2015 and $0.4 million in 2016.

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All PUD drilling locations are scheduled to be drilled prior to the end of 2016.
As of December 31, 2012, 40% of our total proved reserves were classified as proved developed non-producing.
Production, Prices, and Production Costs
The following table presents our production volumes, average prices received and average production costs during the periods indicated:

	2012		2011		2010	
Production Volumes:						
Oil (MBbls)	2,323		2,128		1,777	
Gas (MMcf)	1,108		878		788	
Natural gas liquids (MGal)	2,714		2,468		2,821	
Oil equivalents (MBOE)	2,573		2,333		1,976	
Average Prices:						
Oil (per Bbl)	$104.46	(1)	$104.33	(1)	$68.29	(1)
Gas (per Mcf)	$2.91		$4.37		$4.40	
Natural gas liquids (per Gal)	$0.98		$1.25		$1.00	
Oil equivalents (per BOE)	$96.63		$98.13		$64.61	
Production Costs:						
Average production costs (per BOE)	$9.45		$8.96		$8.92	
Average production taxes (per BOE)	$11.43		$11.29		$7.07	
Total production costs and production taxes (per BOE)	$20.88		$20.25		$15.99	

(1) Includes various derivative contracts at a weighted average price of:

January – December 2012	$108.31
January – December 2011	$86.96
January – December 2010	$57.55

Excluding the effect of fixed price swaps, the average oil price for 2012 would have been $106.11 per barrel of oil and $98.12 per BOE. The total volume hedged for 2012 represented approximately 46% of our total sales volumes for the year. Excluding the effect of fixed price swap contracts, the average oil price for 2011 would have been $107.13 per barrel of oil and $100.68 per BOE. The total volume hedged for 2011 represented approximately 31% of our total sales volumes for the year. Excluding the effect of forward sales contracts, the average oil price for 2010 would have been $78.12 per barrel of oil and $73.45 per BOE. The total volume hedged for 2010 represented approximately 45% of our total sales volumes for the year.
The following table provides a summary of our production, average sales prices and average production costs for oil and gas fields containing 15% or more of our total proved reserves as of December 31, 2012:

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	Year Ended December 31,		
	2012	2011	2010
WCBB			
Net Production			
Oil (MBbls)	1,126	1,258	1,176
Gas (MMcf)	260	237	410
NGL (Mgal)	—	—	—
Total (MBOE)	1,169	1,298	1,244
Average Sales Price:			
Oil (per Bbl)	$105.19	$104.49	$62.57
Gas (per Mcf)	$2.89	$4.16	$4.44
NGL (per Gal)	$—	$—	$—
Average Production Cost (per BOE)	$9.66	$8.71	$8.90
Utica Shale			
Net Production			
Oil (MBbls)	25	—	—
Gas (MMcf)	365	—	—
NGL (Mgal)	80	—	—
Total (MBOE)	87	—	—
Average Sales Price:			
Oil (per Bbl)	$78.21	$—	$—
Gas (per Mcf)	$2.99	$—	$—
NGL (per Gal)	$1.56	$—	$—
Average Production Cost (per BOE)	$8.30	$—	$—

Productive Wells and Acreage

The following table presents our total gross and net productive and non-productive wells, expressed separately for oil and gas, and the total gross and net developed and undeveloped acres as of December 31, 2012.

	NRI/WI (1)	Productive Oil Wells (2)		Productive Gas Wells		Non-Productive Oil Wells		Non-Productive Gas Wells		Developed Acreage (3)		Undeveloped Acreage	
Field	Percentages	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
West Cote Blanche Bay Field (4)	80.108/100	108	108	1	1	163	163	18	18	5,668	5,668	—	—
E. Hackberry Field (5)	80.309/100	41	41	—	—	96	96	—	—	3,931	3,931	581	581
W. Hackberry Field	83.333/100	3	3	—	—	23	23	—	—	1,192	1,192	—	—
Utica Shale (6)	40.641/50.0	1	0.5	1	0.5	—	—	—	—	2,441	1,800	134,693	104,122
Niobrara Formation (7)	36.2/41.5	7	3	—	—	2	1	—	—	2,807	1,404	21,210	10,384
Bakken Formation (8)	2.7/2.9	8	0.2	—	—	—	—	—	—	1,862	163	3,505	701
Overrides/Royalty Non-operated	Various	208	0.4	—	—	2	0.06	—	—	—	—	—	—

Total	376	156.1	2	1.5	286	283.06	18	18	17,901	14,158	159,989	115,788

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(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Includes seven gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 11% of our acreage is developed acreage and has been perpetuated by production.
(4) We have a 100% working interest (80.108% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(5) NRI shown is for producing wells.
(6) Does not give effect to our acquisition of approximately 22,000 additional net acres in February 2013. See "Item 1. Business-Recent Developments-February 2013 Utica Acreage Acquisition."
(7) The leases relating to our Niobrara Formation acreage will expire at the end of their respective primary terms unless the applicable leases are renewed or extended, we have commenced the necessary operations required by the terms of the applicable leases or we have obtained actual production from acreage subject to the applicable leases, in which event they will remain in effect until the cessation of production. Leases representing 45%, 17%, 2%, 12% and 24% of our total Niobrara undeveloped acreage are currently scheduled to expire in 2013, 2014, 2015, 2016 and thereafter, respectively.
(8) NRI/WI is from wells that have been drilled or in which we have elected to participate.

Completed and Present Drilling and Recompletion Activities

The following table sets forth information with respect to 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.

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	92	92	100	96	87	84
Dry	1	0.5	—	—	—	—
Total	93	92.5	100	96	87	84
Development:						
Productive	70	57	82	57	57	42
Dry	8	7	3	3	—	—
Total	78	64	85	60	57	42
Exploratory:						
Productive	19	6	1	1	—	—
Dry	—	—	—	—	—	—
Total	19	6	1	1	—	—

Title to Oil and Natural Gas Properties

It is customary in the oil and natural gas industry to make only a cursory review of title to undeveloped oil and natural gas leases at the time they are acquired and to obtain more extensive title examinations when acquiring producing properties. In future acquisitions, we will conduct title examinations on material portions of such properties in a manner generally consistent with industry practice. Certain of our oil and natural gas properties may be subject to title defects, encumbrances, easements, servitudes or other restrictions, none of which, in management's opinion, will in the aggregate materially restrict our operations.

ITEM 3. LEGAL PROCEEDINGS

The Louisiana Department of Revenue, or LDR, is disputing our severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2007. The LDR maintains that we paid approximately $1.8 million less in severance taxes under fixed price terms than the severance taxes we would have had to pay had we paid severance taxes on the oil at the contracted market rates only. We have denied any liability to the LDR for underpayment of severance taxes and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. We have maintained our right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against our company seeking $2,275,729 in severance taxes, plus interest and court costs. We filed a response denying any liability to the LDR for underpayment of severance taxes and are defending our company in the lawsuit. The LDR had taken no further action on this lawsuit since filing its petition other than propounding discovery requests to which we have responded. Since serving discovery requests on the LDR and received the LDR's responses in 2012, there has been no further activity on the case and no trial date has been set.

In December 2010, the LDR filed two identical lawsuits against us in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney's fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the first lawsuit filed by the LDR in 2009, we have denied all liability and will vigorously defend the lawsuit. The cases are in the very early stages, and we have not yet filed a response to these lawsuits. Recently, the LDR filed motions to stay the lawsuits before we filed any responsive pleadings. The LDR has advised us that it intends to pursue settlement discussions with us and other similarly situated defendants in separate proceedings, but has taken no action to initiate settlement talks. There has been no activity on either of these lawsuits for two years.

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit against us, Great White Pressure Control LLC, or Great White, and six former Cudd employees in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleged RICO violations and several other causes of action relating to Great White's employment of the former Cudd employees and sought unspecified monetary damages and injunctive relief. On stipulation by the parties, the plaintiff's RICO claim was dismissed without prejudice by order of the court on February 14, 2007. We filed a motion for summary judgment on October 5, 2007. The Court entered a final interlocutory judgment in favor of all defendants, including us, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit vacated the district court decision finding, among other things, that the district court should not have entered summary judgment without first allowing more discovery. The case was remanded to the district court, and Cudd filed a motion to remand the case to the original state court, which motion was granted. Cudd subsequently filed amended petitions with the state court (a) alleging, among other things, that we conspired with the other defendants to misappropriate, and misappropriated Cudd's trade secrets and caused its employees to breach their fiduciary duties, and (b) seeking monetary damages, including $11.8 million as a reasonable royalty for the alleged use of its trade secrets. Cudd also sought disgorgement of the alleged benefits received by the various defendants. Cudd also sought its attorney's fees, which Cudd claimed were not less than $450,000 plus 10% of any final judgment. This case went to trial on September 5, 2012 and on September 28, 2012 the jury rendered its verdict, awarding no damages to the plaintiffs. We along with all defendants filed a Motion for Entry of Judgment that is consistent with the jury's verdict. Cudd filed an Application for Disgorgement and a Motion for Judgment Notwithstanding the Verdict. The court denied all of Cudd's post-trial motions on October 12, 2012, the court issued its final judgment on January 10, 2013. On that same day, Cudd filed motions for a new trial and to modify, correct or reform the judgment. Those motions remain pending.

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for contamination across the surface of where the defendants operated in an action entitled Reeds et al. v. BP American Production Company et al., 38th Judicial District. No. 10-18714. The plaintiffs' original petition for damages, which did not name us as a defendant, alleges that the plaintiffs' property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. Plaintiffs allege that the defendants conducted, directed and participated in various oil and gas exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, we were served with a copy of the plaintiffs' first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including us, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses; and damages for evaluation and remediation of any contamination that threatens groundwater. In addition to us, current defendants include ExxonMobil Oil Corporation, Mobil Exploration & Producing North America Inc., Chevron U.S.A. Inc., The Superior

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Oil Company, Union Oil Company of California, BP America Production Company, Tempest Oil Company, Inc., ConocoPhillips Company, Continental Oil Company, WM. T. Burton Industries, Inc., Freeport Sulphur Company, Eagle Petroleum Company, U.S. Oil of Louisiana, M&S Oil Company, and Empire Land Corporation, Inc. of Delaware. On January 21, 2011, we filed a pleading challenging the legal sufficiency of the petitions on several grounds and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. In response to the pleadings filed by us and similar pleadings filed by other defendants, the plaintiffs filed a third amending petition with exhibits which expands the description of the property at issue, attaches numerous aerial photos and identifies the mineral leases at issue. In response, we and numerous defendants re-urged their pleadings challenging the legal sufficiency of the petitions. Some of the defendants' grounds for challenging the plaintiffs' petitions were heard by the court on May 25, 2011 and were denied. The court signed the written judgment on December 9, 2011. We noticed our intent to seek supervisory review on December 19, 2011 and the trial court fixed a return date of January 11, 2012 for the filing of the writ application. We filed our supervisory writ, which was denied by the Louisiana Third Circuit Court of Appeal and the Louisiana Supreme Court. We have been active in serving discovery requests and responding to discovery requests from the plaintiffs. A trial date has been set for September 2013.

Due to the early stages of the LDR and Reed litigation, the outcome is uncertain and management cannot determine the amount of loss, if any, that may result. In each case, management has determined the possibility of loss is remote. However, litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse affect on our financial condition or results of operations and management cannot determine the amount of loss, if any, that may result.

We have been named as a defendant in various other lawsuits related to our business. In each such case, management has determined that the possibility of loss is remote. The resolution of these matters is not expected to have a material adverse effect on our financial condition or results of operations in future periods.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

Price Range of Common Stock

Our common stock is quoted on the NASDAQ Global Select Market under the symbol "GPOR." The following table sets forth the high and low sale prices of our common stock for the periods presented:

	Price Range of Common Stock	
	High	Low
2011		
First Quarter	$36.38	$20.00
Second Quarter	38.09	23.84
Third Quarter	37.49	22.00
Fourth Quarter	37.80	18.72
2012		
First Quarter	$37.63	$27.66
Second Quarter	29.66	15.79
Third Quarter	33.11	18.17
Fourth Quarter	40.73	28.94
2013		
First Quarter (through February 22, 2013)	$42.75	$35.65

On February 22, 2013, the last reported sale price of our common stock on the NASDAQ Global Select Market was $36.91.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Repurchases of Equity Securities

None.

Holders of Record

At the close of business on February 21, 2013, there were 325 stockholders of record holding 77,339,886 shares of our outstanding common stock. There were approximately 26,202 beneficial owners of our common stock as of February 21, 2013.

Dividend Policy

We have never paid dividends on our common stock. We currently intend to retain all earnings to fund our operations. Therefore, we do not intend to pay any cash dividends on the common stock in the foreseeable future. In addition, the terms of our credit facility prohibit the payment of any dividends to the holders of our common stock.

ITEM 6. SELECTED FINANCIAL DATA

You should read the following selected consolidated financial data in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and the related notes appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2012, December 31, 2011 and December 31, 2010 and the selected consolidated balance sheet data at December 31, 2012 and December 31, 2011 are derived from our audited consolidated financial statements appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2009 and

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December 31, 2008 and the selected consolidated balance sheet data at December 31, 2010, December 31, 2009 and December 31, 2008 are derived from our audited consolidated financial statements that are not included in this report. The historical data presented below is not indicative of future results. We did not pay any cash dividends on our common stock during any of the periods set forth in the following table.

	Fiscal Year Ended December 31,				
	2012	2011	2010	2009	2008
Selected Consolidated Statements of Operations Data:					
Revenues	$248,926,000	$229,254,000	$127,921,000	$85,968,000	$141,873,000
Costs and expenses:					
Lease operating expenses	24,308,000	20,897,000	17,614,000	16,316,000	22,856,000
Production taxes	29,400,000	26,333,000	13,966,000	9,797,000	15,813,000
Depreciation, depletion and amortization	90,749,000	62,320,000	38,907,000	29,225,000	42,472,000
Impairment of oil and natural gas properties	—	—	—	—	272,722,000
General and administrative	13,808,000	8,074,000	6,063,000	4,992,000	6,843,000
Accretion expense	698,000	666,000	617,000	582,000	560,000
Gain on sale of assets	(7,300,000)	—	—	—	—
	151,663,000	118,290,000	77,167,000	60,912,000	361,266,000
Income (Loss) from Operations	97,263,000	110,964,000	50,754,000	25,056,000	(219,393,000)
Other (Income) Expense:					
Interest expense	7,458,000	1,400,000	2,761,000	2,309,000	4,762,000
Insurance recoveries	—	—	—	(1,050,000)	(769,000)
Settlement of fixed price contracts	—	—	—	—	(39,000,000)
Interest income	(72,000)	(186,000)	(387,000)	(564,000)	(540,000)
(Income) loss from equity method investments	(8,322,000)	1,418,000	977,000	706,000	656,000
	(936,000)	2,632,000	3,351,000	1,401,000	(34,891,000)
Income (Loss) from Continuing Operations before Income Taxes	98,199,000	108,332,000	47,403,000	23,655,000	(184,502,000)
Income Tax Expense (Benefit)	26,363,000	(90,000)	40,000	28,000	—
Income (Loss) from Continuing Operations	71,836,000	108,422,000	47,363,000	23,627,000	(184,502,000)
Discontinued Operations:					
Loss on disposal of Belize properties, net of tax	3,465,000	—	—	—	—
Net Income (Loss) Available to Common Stockholders	$68,371,000	$108,422,000	$47,363,000	$23,627,000	$(184,502,000)
Net Income (Loss) Per Common Share—Basic:	$1.22	$2.22	$1.08	$0.55	$(4.33)
Net Income (Loss) Per Common Share—Diluted:	$1.21	$2.20	$1.07	$0.55	$(4.33)

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	At December 31, 2012	2011	2010	2009	2008
Selected Consolidated Balance Sheet Data:					
Total assets	$1,578,368,000	$691,158,000	$319,693,000	$227,344,000	$221,873,000
Total debt, including current maturity	$299,038,000	$2,283,000	$51,917,000	$52,428,000	$70,731,000
Total liabilities	$451,960,000	$58,808,000	$108,637,000	$102,293,000	$107,772,000
Stockholders' equity	$1,126,408,000	$632,350,000	$211,056,000	$125,051,000	$114,101,000

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

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. This discussion contains forward-looking statements reflecting our current expectations, 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 Item 1A. "Risk Factors" and the section entitled "Cautionary Note Regarding Forward-Looking Statements" appearing elsewhere in this Annual Report on Form 10-K.

Overview

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields and in the Utica Shale in Eastern Ohio. During 2010, we acquired our initial acreage position in the Niobrara Formation of Northwestern Colorado and, during 2011, we acquired our initial acreage position in the Utica Shale in Eastern Ohio. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, a 21.4% equity interest in Diamondback Energy, Inc., or Diamondback, a NASDAQ Global Select Market listed company to which we contributed our Permian Basin oil and gas interests in October 2012 immediately prior to Diamondback's initial public offering, or the Diamondback IPO (see "Item 1. Business-Recent Developments-Contribution" above), and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

2012 and 2013 Year to Date Highlights

- Oil and natural gas revenues increased 9% to $248.6 million for the year ended December 31, 2012 from $229.0 million for the year ended December 31, 2011.
- Production increased 10% to approximately 2,572,618 barrels of oil equivalent, or BOE, for the year ended December 31, 2012 from approximately 2,333,208 BOE for the year ended December 31, 2011.
- During 2012, we drilled 94 gross (71 net) wells, which included 23 gross (8.4 net) wells drilled by our operators in the Permian Basin, the Niobrara Formation and the Bakken Formation. In addition, 12 gross (one net) wells were drilled by another operator on our Utica Shale acreage during 2012. During 2012 we recompleted 94 gross (93 net) wells. Of our 94 new wells drilled, 69 were completed as producing wells and eight were non-productive and, at year end, 13 were waiting on completion and four were drilling.
- During 2011 and 2012, we acquired leasehold interests in approximately 137,000 gross (106,000 net) acres in the Utica Shale in Eastern Ohio, including the approximately 37,000 net acres acquired in December 2012. In February 2013, we acquired approximately 22,000 additional net acres in the Utica Shale. We spud our first well on our Utica Shale acreage in February 2012 and, as of February 15, 2013, had spud 16 wells, of which three were producing, seven had been completed, four were waiting on completion and two were being drilled.
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- In October 2012, we contributed to Diamondback, prior to the closing of the Diamondback IPO, all of our oil and natural gas interests in the Permian Basin for shares of Diamondback common stock and a promissory note, which was repaid to us at the closing of the Diamondback IPO. As of October 23, 2012, following the closing of the Diamondback IPO and the underwriters' exercise in full of their option to purchase additional shares of common stock of Diamondback, we owned approximately 21.4% of Diamondback's outstanding common stock.
- In October and December of 2012, we issued a total of $300.0 million in aggregate principal amount of our 7.750% Senior Notes due 2020, resulting in net proceeds to us of approximately $290.3 million, a portion of which we used to repay all outstanding borrowings under our senior secured revolving credit facility. We intend to use the remaining net proceeds for general corporate purposes, which may include funding a portion of our 2013 capital development plan.

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- In December of 2012, we completed an underwritten public offering of an aggregate of 11,750,000 shares of our common stock (including the partial exercise of an over-allotment option for 1,650,000 shares granted to the underwriters, which option was exercised to the extent of 750,000 shares). In January 2013, the underwriters exercised their option to purchase the remaining 900,000 shares of our common stock to cover over-allotments. We received net proceeds of approximately $460.7 million through these sales of our common stock. We used approximately $372.0 million to fund our acquisition of approximately 37,000 net acres in the Utica Shale in Eastern Ohio and we intend to use the remaining net proceeds for general corporate purposes, which may include funding a portion of our 2013 capital development plan.
- In February 2013, we completed an underwritten public offering of an aggregate of 8,912,500 shares of our common stock (including the exercise in full of an over-allotment option for 1,162,500 shares granted to the underwriters). We received net proceeds of approximately $325.8 million from this offering. We used approximately $220.4 million to fund our acquisition of approximately 22,000 net acres in the Utica Shale in Eastern Ohio and we intend to use the remaining net proceeds for general corporate purposes, which may include funding a portion of our 2013 capital development plan.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates including those related to oil and natural gas properties, revenue recognition, income taxes and commitments and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements:

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the period 2012, 2011 and 2010, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled $626.3 million at December 31, 2012 and $138.6 million at December 31, 2011. These costs are reviewed quarterly by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the period January - December of the applicable year beginning with 2009, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. For instance, as a result of the drop in commodity prices on December 31, 2008 and subsequent reduction in our proved reserves, we recognized a ceiling test impairment of $272.7 million for the year ended December 31, 2008. If prices of oil, natural gas and natural gas liquids decline, we may be required to further write down the value of our oil and gas properties, which could negatively affect our results of operations. No ceiling test impairment was required for the year ended December 31, 2012.

Asset Retirement Obligations. We have obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities.

We account for abandonment and restoration liabilities under FASB ASC 410 which requires us to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment or retirement, annual inflations of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjustment risk free interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. NSAI, Ryder Scott and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2012 on a well-by-well basis for our properties.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows derived from these reserve estimates have been prepared in accordance with SEC guidelines. The accuracy of our reserve estimates is a function of many factors including the following:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. Therefore, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management's opinion, it is more likely than not that some portion will not be realized. At

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December 31, 2012, a valuation allowance of $4.6 million had been provided for state net operating loss and federal tax credit deferred tax assets based on the uncertainty these assets may be realized.

Revenue Recognition. We derive almost all of our revenue from the sale of crude oil and natural gas produced from our oil and gas properties. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment on substantially all of these sales from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers that month and the price we will receive. Variances between our estimated revenue and actual payment received for all prior months are recorded at the end of the quarter after payment is received. Historically, our actual payments have not significantly deviated from our accruals.

Investments—Equity Method. Investments in entities greater than 20% and less than 50% are accounted for under the equity method. Under the equity method, our share of investees’ earnings or loss is recognized in the statement of operations. In accordance with FASB ASC 825, "Financial Instruments," we have elected the fair value option of accounting for our equity method investment in Diamondback's stock. At the end of each reporting period, the quoted closing market price of Diamondback's stock is multiplied by the total shares owned by us and the resulting gain or loss is recognized in (income) loss from equity method investments in the consolidated statements of operations.

We review our investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, we recognize an impairment provision. There was no impairment of equity method investments at December 31, 2012 or 2011.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. We are involved in certain litigation for which the outcome is uncertain. Changes in the certainty and the ability to reasonably estimate a loss amount, if any, may result in the recognition and subsequent payment of legal liabilities.

Derivative Instruments and Hedging Activities. We seek to reduce our exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. We follow the provisions of FASB ASC 815, “Derivatives and Hedging,” as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and our realized prices, time to maturity and credit risk. The values reported in the financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. We recognize any change in fair value resulting from ineffectiveness immediately in earnings.

To mitigate the effects of commodity price fluctuations, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period January 2010 through February 2010. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through July 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from August 2012 through December 2012, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $107.29 per barrel. For the period from January 2013 through December 2013, we have entered into fixed price swaps for 5,000 barrels of oil per day at a weighted average price of $100.90 per barrel. Under the 2011 contracts, we hedged approximately 31% of our 2011 production. Under the 2012 contracts, we hedged approximately 46% of our 2012 production. Under the 2013 contracts, we have hedged approximately 23% of our estimated 2013 production. Such 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. These forward sales contacts and fixed price swaps are

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accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815, “Derivatives and Hedging,“ and related pronouncements.

RESULTS OF OPERATIONS

Results of Operations

The markets for oil and natural gas have historically been, and will continue to be, volatile. Prices for oil and natural gas may fluctuate in response to relatively minor changes in supply and demand, market uncertainty and a variety of factors beyond our control.

The following table presents our production volumes, average prices received and average production costs during the periods indicated:

	2012		2011		2010	
Production Volumes:						
Oil (MBbls)	2,323		2,128		1,777	
Gas (MMcf)	1,108		878		788	
Natural gas liquids (MGal)	2,714		2,468		2,821	
Oil equivalents (MBOE)	2,573		2,333		1,976	
Average Prices:						
Oil (per Bbl)	$104.46	(1)	$104.33	(1)	$68.29	(1)
Gas (per Mcf)	$2.91		$4.37		$4.40	
Natural gas liquids (per Gal)	$0.98		$1.25		$1.00	
Oil equivalents (per BOE)	$96.63		$98.13		$64.61	
Production Costs:						
Average production costs (per BOE)	$9.45		$8.96		$8.92	
Average production taxes (per BOE)	$11.43		$11.29		$7.07	
Total production costs and production taxes (per BOE)	$20.88		$20.25		$15.99	

(1) Includes various derivative contracts at a weighted average price of:

January – December 2012	$108.31
January – December 2011	$86.96
January – December 2010	$57.55

Excluding the net effect of fixed price swaps, the average oil price for 2012 would have been $106.11 per barrel of oil and $98.12 per BOE. The total volume hedged for 2012 represented approximately 46% of our total sales volumes for the year. Excluding the net effect of fixed price swap contracts, the average oil price for 2011 would have been $107.13 per barrel of oil and $100.68 BOE. The total volume hedged for 2011 represented approximately 31% of our total sales volumes for the year. Excluding the net effect of forward sales contracts, the average oil price for 2010 would have been $78.12 per barrel of oil and $73.45 per BOE. The total volume hedged for 2010 represented approximately 45% of our total sales volumes for the year.

From 2011 to 2012, our net equivalent oil production increased 10% from 2,333,208 BOE to 2,572,618 BOE due to the results of our 2012 drilling and recompletion activities. From 2010 to 2011, our net equivalent oil production also increased 18% from 1,975,576 BOE to 2,333,208 BOE due to the results of our 2011 drilling and recompletion activities. We currently estimate that our 2013 production will be between 7,800,000 and 8,100,000 BOE. However, such estimate may change based on a change in our expected drilling and recompletion activities or the changing economic climate and unforeseen events, such as hurricanes.

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

We reported net income of $68,371,000 for the year ended December 31, 2012 as compared to net income of $108,422,000 for the year ended December 31, 2011. This 37% decrease in period-to-period net income was due primarily to a 2% decrease in realized BOE prices to $96.63 for the year ended December 31, 2012, a 16% increase in lease operating expenses, a 71% increase in general and administrative expenses, a 12% increase in production taxes, an approximately $6.0 million increase in interest expense, a $3.5 million loss on the disposal of our Belize properties, net of tax, and a $24.2 million increase in income taxes from continuing and discontinued operations, partially offset by a 10% increase in net production to 2,572,618 BOE, a gain on sale of assets of $7.3 million and income from equity method investments of $8.3 million.

Oil and Gas Revenues. For the year ended December 31, 2012, we reported oil and natural gas revenues of $248,601,000 as compared to oil and natural gas revenues of $228,953,000 during 2011. This $19,648,000, or 9%, increase in revenues was primarily attributable to a 10% increase in net production to 2,572,618 BOE from 2,333,208 BOE, partially offset by a 2% decrease in realized BOE prices to $96.63 from $98.13, for the year ended December 31, 2012 as compared to the year ended December 31, 2011.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2012 and December 31, 2011:

	Year Ended December 31,	
	2012	2011
Oil production volumes (MBbls)	2,323	2,128
Gas production volumes (MMcf)	1,108	878
Natural gas liquids production volumes (MGal)	2,714	2,468
Oil equivalents (MBOE)	2,573	2,333
Average oil price (per Bbl)	$104.46	$104.33
Average gas price (per Mcf)	$2.91	$4.37
Average natural gas liquids (per Gal)	$0.98	$1.25
Oil equivalents (per BOE)	$96.63	$98.13

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $24,308,000 for the year ended December 31, 2012 from $20,897,000 for 2011. This increase was mainly the result of an increase in expenses related to property taxes, chemicals and fuel, compressor rentals, contract pumpers, field supervision, equipment repairs and maintenance, salt water disposal and well workovers.

Production Taxes. Production taxes increased to $29,400,000 for the year ended December 31, 2012 from $26,333,000 for 2011. This increase was primarily related to a 10% increase in production partially offset by a 2% decrease in the average realized BOE price received, resulting in a 9% increase in oil and gas revenues.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $90,749,000 for the year ended December 31, 2012, and consisted of $90,230,000 in depletion of oil and natural gas properties and $519,000 in depreciation of other property and equipment, as compared to total DD&A expense of $62,320,000 for 2011. This increase was due to an increase in our full cost pool as a result of our capital activities, an increase in our production and a decrease in our total proved reserves volume used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $13,808,000 for the year ended December 31, 2012 from $8,074,000 for 2011. This $5,734,000 increase was due to an increase in salaries, stock compensation expenses and benefits resulting from an increased number of employees, increases in legal expenses, franchise taxes and fees for auditing and tax services, partially offset by an increase in administrative services reimbursements under the acquisition team agreement and an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

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Accretion Expense. Accretion expense increased to $698,000 for the year ended December 31, 2012 from $666,000 for the same period in 2011.

Interest Expense. Interest expense increased to $7,458,000 for the year ended December 31, 2012 from $1,400,000 for 2011 due to higher outstanding debt balances and higher weighted average interest rates. During 2011, total weighted debt outstanding under our revolving credit facility was approximately $21,084,000 and bore a weighted average interest rate of 3.32%. During 2012, total weighted average debt outstanding under our revolving credit facility was approximately $45.0 million and bore a weighted average interest rate of 2.85%. On October 17, 2012, we issued $250.0 million aggregate principal amount of our 7.75% Senior Notes due 2020, a portion of the proceeds from which was used to repay all outstanding borrowings under our revolving credit facility. On December 21, 2012, we issued an additional $50.0 million aggregate principal amount of our 7.75% Senior Notes due 2020. In addition, we wrote off approximately $1,143,000 of unamortized loan fees associated with our revolving credit facility in conjunction with the lowering of our borrowing base during the year ended December 31, 2012.

Income Taxes. As of December 31, 2012, we had a net operating loss carry forward of approximately $4.3 million, in addition to numerous temporary differences, which gave rise to a net deferred tax liability. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2012, a valuation allowance of $4.6 million had been provided for state net operating loss and federal tax credit deferred tax assets based on the uncertainty these assets may be realized. We recognized an income tax expense from continuing and discontinued operations of $24.1 million for the year ended December 31, 2012.

Comparison of the Years Ended December 31, 2011 and December 31, 2010

We reported net income of $108,422,000 for the year ended December 31, 2011 as compared to net income of $47,363,000 for the year ended December 31, 2010. This 129% increase in period-to-period net income was due primarily to an 18% increase in net production to 2,333,208 BOE and a 52% increase in realized BOE prices to $98.13 for the year ended December 31, 2011, partially offset by a 19% increase in lease operating expenses, a 33% increase in general and administrative expenses and an 89% increase in production taxes.

Oil and Gas Revenues. For the year ended December 31, 2011, we reported oil and natural gas revenues of $228,953,000 as compared to oil and natural gas revenues of $127,636,000 during 2010. This $101,317,000, or 79%, increase in revenues was primarily attributable to an 18% increase in net production to 2,333,208 BOE from 1,975,576 BOE and a 52% increase in realized BOE prices to $98.13 from $64.61, in each case for the year ended December 31, 2011 as compared to the year ended December 31, 2010.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2011 and December 31, 2010:

	Year Ended December 31,	
	2011	2010
Oil production volumes (MBbls)	2,128	1,777
Gas production volumes (MMcf)	878	788
Natural gas liquids production volumes (MGal)	2,468	2,821
Oil equivalents (MBOE)	2,333	1,976
Average oil price (per Bbl)	$104.33	$68.29
Average gas price (per Mcf)	$4.37	$4.40
Average natural gas liquids (per Gal)	$1.25	$1.00
Oil equivalents (per BOE)	$98.13	$64.61

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $20,897,000 for the year ended December 31, 2011 from $17,614,000 for 2010. This increase was mainly the result of an increase in expenses

related to chemicals and fuel, equipment repairs and maintenance, field supervision, overhead, property taxes, rentals, salt water disposal and well workovers.

Production Taxes. Production taxes increased to $26,333,000 for the year ended December 31, 2011 from $13,966,000 for 2010. This increase was primarily related to an 18% increase in production and a 52% increase in the average realized BOE price received resulting in a 79% increase in oil and gas revenues.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $62,320,000 for the year ended December 31, 2011, and consisted of $61,965,000 in depletion of oil and natural gas properties and $355,000 in depreciation of other property and equipment, as compared to total DD&A expense of $38,907,000 for 2010. This increase was due to an increase in our full cost pool as a result of our capital activities, an increase in our production and a decrease in our total proved reserves volume, primarily resulting from the contribution to Diamondback of our Permian Basin oil and natural gas interests, used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $8,074,000 for the year ended December 31, 2011 from $6,063,000 for 2010. This $2,011,000 increase was due to an increase in salaries, stock compensation expenses and benefits resulting from an increased number of employees, increases in legal expenses, franchise taxes and bank fees, partially offset by an increase in administrative services reimbursements under the acquisition team agreement and an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $666,000 for the year ended December 31, 2011 from $617,000 for the same period in 2010.

Interest Expense. Interest expense decreased to $1,400,000 for the year ended December 31, 2011 from $2,761,000 for 2010 due to a decrease in the interest rate paid and the repayment of all of our outstanding debt under our revolving credit facility during the fourth quarter of 2011 so that no amounts were outstanding as of December 31, 2011, as compared to $49,500,000 outstanding as of the same date in 2010. Further, during 2010, in conjunction with the repayment of our prior revolving credit facility on September 30, 2010, we expensed approximately $225,000 in unamortized loan fees associated with this facility, which is included in interest expense in our consolidated statements of operations for the year ended December 31, 2010. Total weighted debt outstanding under our revolving credit facility was $21,084,000 for the year ended December 31, 2011 and $46,931,000 for 2010. As of December 14, 2011 (the latest date during the year ended December 31, 2011 on which we had borrowings outstanding), amounts borrowed under our credit facility bore interest at the Eurodollar rate of 2.26%.

Income Taxes. As of December 31, 2011, we had a net operating loss carry forward of approximately $116.8 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2011, a valuation allowance of $12,347,000 had been provided for deferred tax assets, with the exception of $1,000,000 related to alternative minimum taxes. We recognized an income tax benefit of $90,000 for the year ended December 31, 2011.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, borrowings under our credit facilities and the proceeds from issuances of equity securities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or our oil and natural gas production. During 2012, we received net proceeds (before offering expenses) of approximately $427.9 million from the sale of shares of our common stock and net proceeds of approximately $290.3 million from the Notes Offerings. We received an additional $32.8 million of net proceeds (before offering expenses) in January 2013 following the exercise by the underwriters of their option to purchase an additional 900,000 shares of our common stock to cover over-allotments and an additional $325.8 million of net proceeds (before offering expenses) in

February 2013 from the February 2013 Equity Offering. During 2011, we received aggregate net proceeds (before offering expenses) of approximately $307.1 million from the sale of shares of our common stock.

Net cash flow provided by operating activities was $199,158,000 for the year ended December 31, 2012, as compared to net cash flow provided by operating activities of $158,138,000 for 2011. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 10% increase in our net BOE production, partially offset by a 2% decrease in net realized BOE prices.

Net cash flow provided by operating activities was $158,138,000 for the year ended December 31, 2011 as compared to net cash flow provided by operating activities of $85,835,000 for 2010. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 52% increase in net realized BOE prices and an 18% increase in our net BOE production.

Net cash used in investing activities for the year ended December 31, 2012 was $840,579,000 as compared to $323,248,000 for 2011. During the year ended December 31, 2012, we spent $757,192,000 in additions to oil and natural gas properties, of which $175,401,000 was spent on our 2012 drilling and recompletion programs, $38,838,000 was spent on expenses attributable to the wells drilled and recompleted during 2011, $13,309,000 was spent on compressors and other facility enhancements, $1,699,000 was spent on plugging costs, $509,806,000 was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, and $4,990,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, during the year ended December 31, 2012, $103,915,000 was invested in Grizzly and an aggregate of $43,392,000 was invested in our other equity investments. During the year ended December 31, 2012, we used cash from operations and proceeds from the Notes Offerings and the December 2012 Equity Offering for our investing activities.

Net cash used in investing activities for the year ended December 31, 2011 was $323,248,000 as compared to $105,315,000 for 2010. During the year ended December 31, 2011, we spent $287,292,000 in additions to oil and natural gas properties, of which $106,947,000 was spent on our 2011 drilling and recompletion programs, $31,872,000 was spent on expenses attributable to the wells drilled and recompleted during 2010, $8,320,000 was spent on compressors and other facility enhancements, $177,000 was spent on plugging costs, $124,713,000 was spent on lease related costs, primarily the acquisition of leases in the Utica Shale and $3,651,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, $3,182,000 was loaned to, and $22,676,000 was invested in, Grizzly during the year ended December 31, 2011, and $3,794,000, $6,009,000 and $2,142,000 was invested in our investments in Tatex III, Bison and Muskie, respectively, during the year ended December 31, 2011. During the year ended December 31, 2011, we used cash from operations and proceeds from our equity offering for our investing activities.

Net cash provided by financing activities for the year ended December 31, 2012 was $714,612,000 as compared to $256,539,000 for 2011. The 2012 amount provided by financing activities was primarily attributable to the net proceeds of $426,907,000 from the December 2012 Equity Offering (not including the $32,776,000 received in January 2013 following the exercise by the underwriters of the December 2012 Equity Offering of their option to purchase an additional 900,000 shares of our common stock to cover over-allotments), $296,835,000 from our offerings of 7.750% Senior Notes due 2020 and $184,000 from the exercise of stock options.

Net cash provided by financing activities for the year ended December 31, 2011 was $256,539,000 as compared to $20,224,000 for 2010. The 2011 amount provided by financing activities was primarily attributable to the net proceeds of $307,154,000 from our equity offerings and exercise of stock options, partially offset by net principal payments of $49,500,000 on borrowings under our credit facility. The 2010 amount provided by financing activities was primarily attributable to the net proceeds from our equity offerings of $21,358,000.

Credit Facility. On September 30, 2010, we entered into a senior secured revolving credit facility with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association, or Amegy Bank. The revolving credit facility initially matured on September 30, 2013, had a maximum commitment amount of $100.0 million and had a borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010. On May 3, 2011, we entered into a first amendment to the revolving credit facility with The Bank of Nova Scotia, Amegy Bank, KeyBank National Association, or KeyBank, and Société Générale. Under the terms of the first amendment, KeyBank and Société Générale were added as additional lenders, the maximum amount of the revolving credit facility was increased to $350.0 million, the borrowing base was increased to $90.0 million, certain fees and rates payable by us under the credit facility were decreased, and the maturity date was extended until May 3, 2015. On October 31, 2011, we entered into additional amendments to our revolving credit facility pursuant to which, among other things, the borrowing base under the facility was increased to

$125.0 million. On December 14, 2011, we repaid all outstanding borrowings under the credit facility with a portion of the net proceeds of our equity offering completed on December 5, 2011 pending the application of such proceeds to fund certain Utica Shale lease acquisitions and for general corporate purposes. On May 2, 2012, we entered into an amendment to the revolving credit facility under which, among other things, the borrowing base was increased to $155.0 million. In addition, Credit Suisse, Deutsche Bank Trust Company Americas and IBERIABANK were added as additional lenders and Société Générale left the bank group. As of December 31, 2012, there were no borrowings outstanding under our revolving credit facility. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guarantee our obligations under our revolving credit facility.

On October 9, 2012, we entered into an amendment to our revolving credit facility that modified certain covenants to permit the October Notes Offering. The October Notes Offering closed on October 17, 2012 and we repaid all indebtedness outstanding under our revolving credit facility on that date with a portion of the proceeds from the October Notes Offering. Effective as of October 17, 2012, we amended our revolving credit facility to lower the applicable rates (i) from a range of 1.00% to 1.75% to a range of 0.75% to 1.50% for the base rate loans and (ii) from a range of 2.00% to 2.75% to a range of 1.75% to 2.50% for the Eurodollar rate loans and letters of credit. This amendment also lowered the commitment fees for Level 1 and Level 2 usage levels, in each case, from 0.50% per annum to 0.375% per annum. Also, effective as of October 17, 2012, in connection with the completion of the October Notes Offering and the Contribution, our borrowing base under the credit facility was reduced to $45.0 million until the next borrowing base redetermination. Effective as of December 18, 2012, we entered into another amendment to our revolving credit facility that modified certain covenants to permit the December Notes Offering and reduce the borrowing base under our revolving credit facility to $40.0 million until the next borrowing base redetermination.

Advances under our revolving credit facility, as amended, may be in the form of either base rate loans or Eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from .75% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its “prime rate,” and (c) the Eurodollar rate for an interest period of one month plus 1.00%. The interest rate for Eurodollar loans is equal to (1) the applicable rate, which ranges from 1.75% to 2.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the “London Interbank Offered Rate” for deposits in U.S. dollars. We have had no outstanding borrowings under our revolving credit facility since October 17, 2012, on which date the outstanding borrowings, prior to repayment, bore interest at the Eurodollar rate (2.97%) per annum.

Our revolving credit facility contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries' ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in our revolving credit facility. Our revolving credit facility also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offerings, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with these financial covenants at December 31, 2012.

Senior Notes. On October 17, 2012, we issued $250.0 million in aggregate principal amount of our 7.750% Senior Notes due 2020, or the October Notes, to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act under an indenture among us, our subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee.

On December 21, 2012, we issued an additional $50.0 million in aggregate principal amount of our 7.750% Senior Notes due 2020, or the December Notes, to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. The December Notes were issued as additional securities under the existing senior note indenture. The December Notes and the October Notes are treated as a single class of debt securities under the senior note indenture. We used a portion of the net proceeds from the October Notes Offering to repay all amounts outstanding at such time under our revolving credit facility. We intend to use the remaining net proceeds of October Notes Offering and the net proceeds of the December Notes Offering for general corporate purposes, which may include funding a portion of our 2013 capital development plan.

Under the senior note indenture, interest on the Notes accrues at a rate of 7.750% per annum on the outstanding principal amount from October 17, 2012, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2013.

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The Notes are senior unsecured obligations and rank equally in the right of payment with all of our other senior indebtedness and senior in right of payment to any of our future subordinated indebtedness. All of our existing and future restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt guarantee the Notes, provided, however, that the Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of our future unrestricted subsidiaries. The guarantees rank equally in the right of payment with all of the senior indebtedness of the subsidiary guarantors and senior in the right of payment to any future subordinated indebtedness of the subsidiary guarantors. The Notes and the guarantees are effectively subordinated to all of our and the subsidiary guarantors' secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries that do not guarantee the Notes.

We may redeem some or all of the Notes at any time on or after November 1, 2016, at the redemption prices listed in the senior note indenture. Prior to November 1, 2016, we may redeem the Notes at a price equal to 100% of the principal amount plus a “make-whole” premium. In addition, prior to November 1, 2015, we may redeem up to 35% of the aggregate principal amount of the Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the Notes initially issued remains outstanding immediately after such redemption.

If we experience a change of control (as defined in the senior note indenture), we will be required to make an offer to repurchase the Notes at a price equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. If we sell certain assets and fail to use the proceeds in a manner specified in the senior note indenture, we will be required to use the remaining proceeds to make an offer to repurchase the Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

The senior note indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of our restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of our subsidiaries as unrestricted subsidiaries.

Building Loans. In June 2004, we purchased the office building we occupy in Oklahoma City, Oklahoma, for $3.7 million. We entered into a new building loan in March 2011 to refinance the $2.4 million outstanding at that time. The new agreement matures in February 2016 and bears interest at a fixed rate of 5.82% per annum. The new building loan requires monthly interest and principal payments of approximately $22,000 and is collateralized by the Oklahoma City office building and associated land. As of December 31, 2012, approximately $2.1 million was outstanding on this loan.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions of oil and natural gas interests in the Utica Shale, Permian Basin and the Niobrara Formation, to fund Grizzly's delineation drilling program and initial preparation of the Algar Lake facility and for investments in entities that may provide services to facilitate the development of our acreage. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties, subject to economic and industry conditions, and (2) pursue acquisition and disposition opportunities and (3) business integration opportunities.

Of our net reserves at December 31, 2012, 40.2% were categorized as proved undeveloped. 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 developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

At December 31, 2012, our booked inventory of prospects included approximately 36 drilling locations at WCBB. The drilling schedule used in our December 31, 2012 reserve report anticipates that all of those wells will be drilled by the end of 2015. During 2012, we recompleted 61 wells and drilled 31 wells, of which 27 were completed as producers and four were non-productive, for an aggregate cost of $68.2 million. From January 1, 2013 through February 15, 2013, we recompleted 12 existing wells at our WCBB field. We currently intend to recomplete 60 wells and drill 22 to 24 new wells during 2013 at our WCBB field. Our aggregate drilling and recompletion expenditures for our WCBB field during 2013 are estimated to be approximately $42.0 million to $45.0 million.

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In our Hackberry fields, in 2012, we recompleted 32 existing wells and drilled 24 wells, of which 19 were completed as producers, three were non-productive and, at December 31, 2012, two were drilling, for an aggregate cost of $70.1 million. From January 1, 2013 through February 15, 2013, we recompleted two existing wells and drilled two new wells at our East Hackberry field and, at February 15, 2013, we were in the process of drilling one additional well at our East Hackberry field. We currently intend to drill ten to twelve wells and recomplete 24 wells in our Hackberry fields in 2013. Total capital expenditures for our Hackberry fields during 2013 are estimated to be approximately $26.0 million to $28.0 million.

From January 1, 2012 through October 11, 2012, 19 gross (8.3 net) wells were spud on our Permian Basin acreage, all of which were completed as producers and one gross (0.3 net) existing well was recompleted between January 1, 2012 and October 11, 2012, for an aggregate cost of $20.9 million. As discussed above under the heading "Item 1. Business-Recent Developments-Contribution," on October 11, 2012, we contributed all of our oil and gas interests in the Permian Basin to Diamondback. We have no further funding obligations for operations relating to this Permian Basin acreage conducted after October 11, 2012.

In the Niobrara Formation in Northwestern Colorado, in 2011, we completed a 60 square mile 3-D seismic survey and have received a processed version of the seismic data. During 2012, three gross (one net) wells, including one gross (.04 net) well drilled by another operator, were spud on our Niobrara Formation acreage, two of which were completed as producers and one of which was non-productive. Our total capital expenditures with respect to these three gross wells in the Niobrara Formation were approximately $2.5 million. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2013.

In the Utica Shale in Eastern Ohio, in 2011 and 2012, we acquired approximately 137,000 gross (106,000 net) acres for approximately $626.9 million. As of December 31, 2012, we had drilled 14 wells on our Utica Shale acreage. Our total lease acquisition costs in the Utica Shale during 2012 were approximately $508.5 million. In addition, during 2012, we spent approximately $66.1 million to drill 14 gross (6.7 net) wells on our Utica acreage. In February 2013, we acquired approximately 22,000 additional net acres in the Utica Shale. We currently intend to drill 50 gross (44 net) wells on our Utica Shale acreage in 2013. Total capital expenditures in the Utica Shale during 2013 are estimated to be approximately $382.0 million to $426.0 million, excluding leasehold acquisitions.

During the third quarter of 2006, we purchased a 24.9% interest in Grizzly. As of December 31, 2012, our net investment in Grizzly was approximately $172.8 million. Our capital requirements in 2012 for Grizzly were approximately $103.9 million, primarily for the expenses associated with the construction of the Algar Lake facility, drilling activity during the 2011-2012 winter drilling season and our $56.3 million share of the cost of the May River property. This acquisition was completed in February 2012 when Grizzly purchased approximately 47,000 acres of oil sands leases in the Athabasca oil sands area for $225.0 million CAD. We funded our portion of the purchase price with borrowings under our revolving credit facility. Effective October 5, 2012, Grizzly entered into a $125.0 million revolving credit facility, of which $75.0 million is initially available for borrowing to fund additional infrastructure relating to the Algar Lake facility and other future development projects. As of that same date, we entered into an agreement with Grizzly in which we committed to make monthly payments from October 2012 to May 2013 in the aggregate amount of approximately $8.5 million (of which $4.0 million was paid in 2012) to fund the construction and development of the Algar Lake facility. We also agreed to fund our proportionate share of any unfunded cost overruns, which we currently expect to be $3.0 million to $7.0 million.

We did not have any capital expenditures in 2012 related to our interests in Thailand. Total 2013 capital expenditures for Thailand are estimated to be $2.0 million to $2.5 million to drill one gross well.

In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In the second quarter of 2012, we acquired a 50% equity interest in each of Stingray Pressure Pumping LLC, or Stingray Pressure, and Stingray Cementing LLC, or Stingray Cementing. Stingray Pressure and Stingray Cementing provide well completion services. We also acquired a 50% equity interest in Blackhawk Midstream LLC, or Blackhawk, which coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage. Blackhawk also has an option to acquire up to a 40% equity interest in the entity that provides midstream services to us in connection with our Utica Shale acreage. In the fourth quarter of 2012, we acquired a 50% equity interest in Stingray Logistics LLC, Stingray Logistics. Stingray Logistics will provide well services. In March 2012, we acquired a 50% equity interest in Timber Wolf Terminals LLC, or Timber Wolf, for $1.0 million. Also in March 2012, we acquired a 22.5% equity interest in Windsor Midstream LLC, or Midstream, for $7.0 million. Midstream owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011, we acquired a 25% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates drilling rigs and related equipment. In April 2012, we purchased an additional 15% equity interest for approximately $6.2 million, bringing our total ownership interest in Bison to 40%. Also in 2011, we acquired a 25% interest in Muskie Holdings LLC, or Muskie, which is engaged in the mining of hydraulic fracturing grade sand. The remaining equity interests in these entities are owned by affiliates of Wexford. In 2012, we invested approximately $42.8 million in these entities. In 2013, we expect to invest approximately $10.0 million to $15.0 million in these entities.

Our total capital expenditures for 2013 are currently estimated to be in the range of $458.0 million to $512.0 million, excluding the acquisition costs associated with our February 2013 Utica Shale acquisition and with any additional Utica Shale acreage or other potential acquisitions and any amounts attributable to Grizzly. Approximately 85% of our 2013 estimated capital expenditures are currently expected to be spent in the Utica Shale. This range is up from the $277.6 million spent on 2012 activities primarily due to the significant increase in our acreage position in the Utica Shale and our contemplated Utica development plans, although such anticipated 2013 expenditures are partially offset relative to 2012 by the elimination of development costs in the Permian Basin as a result of the Contribution. We intend to continue to monitor pricing and cost developments and make adjustments to our future capital expenditure programs as warranted.

We believe that our cash on hand, cash flow from operations, proceeds from our recent offerings of debt and equity securities and borrowings under our revolving credit facility will be sufficient to meet our normal recurring operating needs and capital requirements for the next twelve months. In the event we elect to further expand or accelerate our drilling programs, pursue additional acquisitions, exercise our Blackhawk option or accelerate our Canadian oil sands project, we may be required to obtain additional funds which we would seek to do through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. We regularly evaluate new acquisition opportunities. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

Commodity Price Risk

The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. 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 barrel in December 2008 to a high of $145.31 per barrel 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 $13.31 per MMBtu in July 2008. On December 31, 2012, the West Texas Intermediate posted price for crude oil was $91.82 per barrel and the Henry Hub spot market price of natural gas was $3.35 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, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

To mitigate the effects of commodity price fluctuations, in November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through July 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from August 2012 through December 2012, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $107.29. For the period from January 2013 through December 2013, we have entered into fixed price swaps for 5,000 barrels of oil per day at a weighted average price of $100.90 per barrel. Under the 2011 contracts, we hedged approximately 31% of our 2011 production. Under the 2012 contracts, we hedged approximately 46% of our 2012 production. Under the 2013 contracts, we have hedged approximately 23% of our expected 2013 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

Commitments

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller's (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2012, the plugging and abandonment trust totaled approximately $3.1 million. At December 31, 2012, we have plugged 354 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

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Contractual and Commercial Obligations

The following table sets forth our contractual and commercial obligations at December 31, 2012:

	Payment due by period (1)				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Building loan (2)	$2,143,000	$ 150,000	$326,000	$1,667,000	$—
7.75% senior unsecured notes due 2020	486,000,000	23,250,000	46,500,000	46,500,000	369,750,000
Asset retirement obligations	13,275,000	60,000	1,739,000	820,000	10,656,000
Employment agreements	7,050,000	2,400,000	4,650,000	—	—
Grizzly capital commitments	6,280,000	6,280,000	—	—	—
Operating leases	586,000	179,000	305,000	102,000	—
Total	$515,334,000	$ 32,319,000	$53,520,000	$49,089,000	$380,406,000

(1) Does not include short-term derivative instruments of $9,778,000, which are due in less than one year.

(2) Does not include estimated interest of $121,000 due in less than one year, $214,000 due in 1-3 years and $16,000 due in 3-5 years.

New Accounting Pronouncements

In February 2013, the FASB issued Accounting Standards Update ("ASU") No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income," which requires additional information about amounts reclassified out of accumulated other comprehensive income by component. This ASU requires the presentation, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, a cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. The requirements of this ASU are effective prospectively for reporting periods beginning after December 15, 2012 with early adoption permitted. The Company will adopt the provisions of this ASU for reporting periods in 2013 and does not expect the adoption of this ASU to have a material effect on its consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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, including: worldwide and domestic supplies of oil and natural gas; the level of prices, and expectations about future prices, of oil and natural gas; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; weather conditions, including hurricanes, that can affect oil and natural gas operations over a wide area; the level of consumer demand; the price and availability of alternative fuels; technical advances affecting energy consumption; risks associated with operating drilling rigs; the availability of pipeline capacity; the price and level of foreign imports; domestic and foreign governmental regulations and taxes; the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; political instability or armed conflict in oil and natural gas producing regions; and the overall economic environment.

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 West Texas Intermediate posted price for crude oil 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 MMBtu in September 2009 to a high of $13.31 per MMBtu in July 2008. On February 22, 2013, the West Texas Intermediate posted price for crude oil was $93.13 per barrel and the Henry Hub spot market price of natural gas was $3.27 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, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

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To mitigate the effects of commodity price fluctuations, in November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through July 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from August 2012 through December 2012, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $107.29. For the period from January 2013 through December 2013, we have entered into fixed price swaps for 5,000 barrels of oil per day at a weighted average price of $100.90 per barrel. Under the 2011 contracts, we hedged approximately 31% of our 2011 production. Under the 2012 contracts, we hedged approximately 46% of our 2012 production. Under the 2013 contracts, we have hedged approximately 23% of our estimated 2013 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements. At December 31, 2012, we had a net liability derivative position of $9.8 million as compared to a net asset derivative position of $1.6 million as of December 31, 2011, related to our fixed price swaps. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $19.4 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $19.4 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Our revolving credit facility is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or Eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the Eurodollar rates are elected, the Eurodollar rates. As of October 17, 2012 (the latest date during the year ended December 31, 2012 on which we had borrowings outstanding), amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 2.97%. As of December 31, 2012, we had no variable interest rate borrowings outstanding; therefore, an increase in interest rates would not have impacted our interest expense. As of December 31, 2012, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 following the signature pages of this Report.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of our Chief Executive Officer and Vice President and Chief Financial Officer, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Vice President and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

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

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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Management's Report on Internal Control Over Financial Reporting

Management is responsible for the fair presentation of the consolidated financial statements of Gulfport Energy Corporation. Management is also responsible for establishing and maintaining a system of adequate internal controls over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in Internal Control-Integrated Framework, management did not identify any material weaknesses in our internal control over financial reporting and concluded that our internal control over financial reporting was effective as of December 31, 2012.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2012 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2012, as stated in their accompanying report.

/s/ James D. Palm		/s/ Michael G. Moore	
Name:	James D. Palm	Name:	Michael G. Moore
Title:	Chief Executive Officer	Title:	Chief Financial Officer

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation:

We have audited the internal control over financial reporting of Gulfport Energy Corporation and Subsidiaries (the “Company”) as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2012 and our report dated February 28, 2013 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP
Oklahoma City, Oklahoma
February 28, 2013

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

For information concerning Item 10-Directors, Executive Officers and Corporate Governance, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 11. EXECUTIVE COMPENSATION

For information concerning Item 11-Executive Compensation, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

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

For information concerning Item 12-Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

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

For information concerning Item 13-Certain Relationships and Related Transactions, and Director Independence, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

For information concerning Item 14-Principal Accounting Fees and Services, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report:

(1) Financial Statements

Reference is made to the Index to Financial Statements appearing on Page F-1.

(2) Financial Statement Schedules

All financial statement schedules have been omitted because they are not applicable or the required disclosure is presented in the financial statements or notes thereto.

(3) Exhibits

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of November 28, 2007, by and among Ambrose Energy I, Ltd. and each of the other persons, which are listed as a party seller, and Windsor Permian (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
2.2	Second Amendment to the Purchase and Sale Agreement, dated as of December 18, 2007, by and among Ambrose Energy I, Ltd., each of the other parties which are listed as a party seller, Windsor Permian and Gulfport (incorporated by reference to Exhibit 2.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
2.3	Contribution Agreement, dated May 7, 2012, by and between the Company and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on May 8, 2012).
2.4	Purchase and Sale Agreement, dated December 17, 2012, by and between Windsor Ohio LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 18, 2012).
2.5	Amendment, dated December 19, 2012, to the Purchase and Sale Agreement, dated December 17, 2012, by and between Windsor Ohio LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 20, 2012).
2.6	Purchase and Sale Agreement, dated February 11, 2013, by and between Windsor Ohio, LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 15, 2013).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).

3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.3	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).

4.4	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.5	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
4.6	Indenture, dated as of October 17, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of Gulfport Energy Corporation's 7.750% Senior Note Due November 1, 2020) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
4.7	Registration Rights Agreement, dated as of October 17, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
4.8	First Supplemental Indenture, dated December 21, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).
4.9	Registration Rights Agreement, dated as of December 21, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).
10.1+	Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.3+	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.4+	Employment Agreement, dated November 7, 2012, between the Company and Mike Liddell (incorporated by reference to Exhibit 10.4 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 8, 2012).
10.5+	Employment Agreement, dated November 7, 2012, between the Company and James D. Palm (incorporated by reference to Exhibit 10.5 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 8, 2012).

10.6+	Employment Agreement, dated November 7, 2012, between the Company and Michael G. Moore (incorporated by reference to Exhibit 10.6 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 8, 2012).
10.7	Credit Agreement, dated as of September 30, 2010, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 6, 2010).
10.8	Amendment, dated as of December 24, 2010, to the Credit Agreement by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 28, 2010).
10.9	First Amendment, dated May 3, 2011 of Credit Agreement, dated September 30, 2011, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, Amegy Bank National Association, KeyBank National Association and Société Générale (incorporated by reference to Exhibit 10.2 of Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 9, 2011).
10.10	Second Amendment to Credit Agreement, dated as of October 31, 2011, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, Amegy Bank National Association, as syndication agent, KeyBank National Association, as co-documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.2 of Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 4, 2011).

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10.11	Third Amendment to Credit Agreement, dated as of October 31, 2011, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, Amegy Bank National Association, as syndication agent, KeyBank National Association and Société Générale, as co-documentation agents, and the other lenders party thereto (incorporated by reference to Exhibit 10.2 of Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 4, 2011).
10.12	Fourth Amendment, dated May 2, 2012, to Credit Agreement, dated September 30, 2011, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent and letter of credit issuer, Amegy Bank National Association, Key Bank National Association and Société Générale (incorporated by reference to Exhibit 10.1 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 10, 2012).
10.13	Fifth Amendment to Credit Agreement, effective as of October 9, 2012, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and certain lenders and agents party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 9, 2012).
10.14	Sixth Amendment to Credit Agreement, effective as of October 17, 2012, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and certain lenders and agents party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
10.15	Seventh Amendment to Credit Agreement, effective as of December 18, 2012, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and certain lenders and agents party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).
10.16	Investor Rights Agreement, dated as of October 11, 2012, between Gulfport Energy Corporation and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 17, 2012).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Ryder Scott Company.
23.4*	Consent of Pinnacle Energy Services, LLC.
31.1*	

	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Netherland, Sewell & Associates, Inc.
99.2*	Report of Ryder Scott Company.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.

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101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

*	Filed herewith.
**	Furnished herewith, not filed.
+	Management contract, compensatory plan or arrangement.

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SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 28, 2013

GULFPORT ENERGY CORPORATION

By: /s/ JAMES D. PALM
James D. Palm
Chief Executive Officer

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: February 28, 2013	By: /s/ JAMES D. PALM James D. Palm Chief Executive Officer and Director (Principal Executive Officer)
Date: February 28, 2013	By: /s/ MIKE LIDDELL Mike Liddell Chairman of the Board and Director
Date: February 28, 2013	By: /s/ MICHAEL G. MOORE Michael G. Moore Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
Date: February 28, 2013	By: /s/ DONALD DILLINGHAM Donald Dillingham Director
Date: February 28, 2013	By: /s/ CRAIG GROESCHEL Craig Groeschel Director
Date: February 28, 2013	By: /s/ DAVID L. HOUSTON David L. Houston Director
Date: February 28, 2013	By: /s/ SCOTT E. STRELLER Scott E. Streller Director

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Independent Registered Public Accounting Firm
Board of Directors and Stockholders
Gulfport Energy Corporation:

We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation and Subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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 Gulfport Energy Corporation and Subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 28, 2013 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP
Oklahoma City, Oklahoma
February 28, 2013

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GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(Amounts rounded to nearest thousand)

	December 31, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$167,088,000	$93,897,000
Accounts receivable—oil and gas	25,615,000	28,019,000
Accounts receivable—related parties	34,848,000	4,731,000
Prepaid expenses and other current assets	1,506,000	1,327,000
Short-term derivative instruments	664,000	1,601,000
Total current assets	229,721,000	129,575,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $626,295,000 and $138,623,000 excluded from amortization in 2012 and 2011, respectively	1,611,090,000	1,035,754,000
Other property and equipment	8,662,000	8,024,000
Accumulated depletion, depreciation, amortization and impairment	(665,884,000)	(575,142,000)
Property and equipment, net	953,868,000	468,636,000
Other assets:		
Equity investments ($151,317,000 and $0 attributable to fair value option in 2012 and 2011, respectively)	381,484,000	86,824,000
Other assets	13,295,000	5,123,000
Total other assets	394,779,000	91,947,000
Deferred tax asset	—	1,000,000
Total assets	$1,578,368,000	$691,158,000
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$110,244,000	$43,872,000
Asset retirement obligation—current	60,000	620,000
Short-term derivative instruments	10,442,000	—
Current maturities of long-term debt	150,000	141,000
Total current liabilities	120,896,000	44,633,000
Asset retirement obligation—long-term	13,215,000	12,033,000
Deferred tax liability	18,607,000	—
Long-term debt, net of current maturities	298,888,000	2,142,000
Other non-current liabilities	354,000	—
Total liabilities	451,960,000	58,808,000
Commitments and contingencies (Notes 16 and 17)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding	—	—
Stockholders' equity:		
Common stock - $.01 par value, 100,000,000 authorized, 67,527,386 issued and outstanding in 2012 and 55,621,371 in 2011	674,000	556,000
Paid-in capital	1,036,245,000	604,584,000
Accumulated other comprehensive income (loss)	(3,429,000)	2,663,000

Retained earnings	92,918,000	24,547,000
Total stockholders' equity	1,126,408,000	632,350,000
Total liabilities and stockholders' equity	$1,578,368,000	$691,158,000

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See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts rounded to nearest thousand)

	Year Ended December 31,		
	2012	2011	2010
Revenues:			
Oil and condensate sales	$242,708,000	$222,025,000	$121,350,000
Gas sales	3,225,000	3,838,000	3,468,000
Natural gas liquid sales	2,668,000	3,090,000	2,818,000
Other income	325,000	301,000	285,000
	248,926,000	229,254,000	127,921,000
Costs and expenses:			
Lease operating expenses	24,308,000	20,897,000	17,614,000
Production taxes	29,400,000	26,333,000	13,966,000
Depreciation, depletion, and amortization	90,749,000	62,320,000	38,907,000
General and administrative	13,808,000	8,074,000	6,063,000
Accretion expense	698,000	666,000	617,000
Gain on sale of assets	(7,300,000)	—	—
	151,663,000	118,290,000	77,167,000
INCOME FROM OPERATIONS	97,263,000	110,964,000	50,754,000
OTHER (INCOME) EXPENSE:			
Interest expense	7,458,000	1,400,000	2,761,000
Interest income	(72,000)	(186,000)	(387,000)
(Income) loss from equity method investments	(8,322,000)	1,418,000	977,000
	(936,000)	2,632,000	3,351,000
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	98,199,000	108,332,000	47,403,000
INCOME TAX EXPENSE (BENEFIT)	26,363,000	(90,000)	40,000
INCOME FROM CONTINUING OPERATIONS	71,836,000	108,422,000	47,363,000
DISCONTINUED OPERATIONS			
Loss on disposal of Belize properties, net of tax	3,465,000	—	—
NET INCOME	$68,371,000	$108,422,000	$47,363,000
NET INCOME PER COMMON SHARE:			
Basic net income from continuing operations per share	$1.28	$2.22	$1.08
Basic net income from discontinued operations, net of tax, per share	(0.06)	—	—
Basic net income per share	$1.22	$2.22	$1.08
Diluted net income from continuing operations per share	$1.27	$2.20	$1.07
Diluted net income from discontinued operations, net of tax, per share	(0.06)	—	—
Diluted net income per share	$1.21	$2.20	$1.07
Weighted average common shares outstanding—Basic	55,933,354	48,754,840	43,863,190
Weighted average common shares outstanding—Diluted	56,417,488	49,206,963	44,256,092

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Amounts rounded to nearest thousand)

	2012	2011	2010
Net income	$68,371,000	$108,422,000	$47,363,000
Foreign currency translation adjustment	1,355,000	(1,865,000)	2,255,000
Change in fair value of derivative instruments, net of taxes (1)	(8,452,000)	1,576,000	(4,720,000)
Reclassification of settled contracts, net of taxes (2)	1,005,000	4,720,000	18,736,000
Other comprehensive income (loss)	(6,092,000)	4,431,000	16,271,000
Comprehensive income	$62,279,000	$112,853,000	$63,634,000

(1) Net of $(4,301,000), $0, and $0 in taxes for the years ended December 31, 2012, 2011 and 2010, respectively.

(2) Net of $512,000, $0, and $0 in taxes for the years ended December 31, 2012, 2011 and 2010, respectively.

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Amounts rounded to nearest thousand)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income(Loss)	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
Balance at January 1, 2010	42,696,409	$427,000	$273,901,000	$(18,039,000)	$(131,238,000)	$125,051,000
Net income	—	—	—	—	47,363,000	47,363,000
Other Comprehensive Income	—	—	—	16,271,000	—	16,271,000
Stock Compensation	—	—	492,000	—	—	492,000
Issuance of Common Stock in public offering, net of related expenses	1,668,503	17,000	21,341,000	—	—	21,358,000
Issuance of Common Stock through exercise of warrants	173,109	2,000	204,000	—	—	206,000
Issuance of Restricted Stock	58,525	—	—	—	—	—
Issuance of Common Stock through exercise of options	48,889	—	315,000	—	—	315,000
Balance at December 31, 2010	44,645,435	446,000	296,253,000	(1,768,000)	(83,875,000)	211,056,000
Net income	—	—	—	—	108,422,000	108,422,000
Other Comprehensive Income	—	—	—	4,431,000	—	4,431,000
Stock Compensation	—	—	1,287,000	—	—	1,287,000
Issuance of Common Stock in public offering, net of related expenses	10,810,000	108,000	306,053,000	—	—	306,161,000
Issuance of Common Stock through exercise of warrants	566	—	—	—	—	—
Issuance of Restricted Stock	63,370	1,000	(1,000)	—	—	—
Issuance of Common Stock through exercise of options	102,000	1,000	992,000	—	—	993,000
Balance at December 31, 2011	55,621,371	556,000	604,584,000	2,663,000	24,547,000	632,350,000
Net income	—	—	—	—	68,371,000	68,371,000

Other Comprehensive Loss	—	—	—	(6,092,000)	—	(6,092,000)
Stock Compensation	—	—	4,688,000	—	—	4,688,000
Issuance of Common Stock in public offering, net of related expenses	11,750,000	118,000	426,789,000	—	—	426,907,000
Issuance of Restricted Stock	135,015	—	—	—	—	—
Issuance of Common Stock through exercise of options	21,000	—	184,000	—	—	184,000
Balance at December 31, 2012	67,527,386	$674,000	$1,036,245,000	$(3,429,000)	$92,918,000	$1,126,408,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts rounded to nearest thousand)

	Year Ended December 31,		
	2012	2011	2010
Cash flows from operating activities:			
Net income	$68,371,000	$108,422,000	$47,363,000
Adjustments to reconcile net income to net cash provided by operating activities:			
Accretion of discount—Asset Retirement Obligation	698,000	666,000	617,000
Depletion, depreciation and amortization	90,749,000	62,320,000	38,907,000
Stock-based compensation expense	2,813,000	772,000	295,000
(Gain) loss from equity investments	(8,322,000)	1,418,000	977,000
Interest income—note receivable	(2,000)	(147,000)	(267,000)
Unrealized loss (gain) on derivative instruments	144,000	(25,000)	—
Deferred income tax expense (benefit)	24,120,000	(372,000)	(95,000)
Amortization of loan commitment fees	640,000	540,000	—
Amortization of note discount and premium	59,000	—	—
Write off of loan commitment fees	1,143,000	—	—
Loss on disposal of assets	5,702,000	—	—
Gain on sale of assets	(7,300,000)	—	—
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable	2,404,000	(13,067,000)	(5,460,000)
Increase in accounts receivable—related party	(30,117,000)	(4,158,000)	(437,000)
(Increase) decrease in prepaid expenses	(179,000)	405,000	315,000
Increase in other assets	—	—	(75,000)
Increase in accounts payable and accrued liabilities	50,506,000	1,612,000	4,948,000
Settlement of asset retirement obligation	(2,271,000)	(248,000)	(1,253,000)
Net cash provided by operating activities	199,158,000	158,138,000	85,835,000
Cash flows from investing activities:			
Deductions to cash held in escrow	8,000	8,000	8,000
Additions to other property, plant and equipment	(638,000)	(415,000)	(427,000)
Additions to oil and gas properties	(757,192,000)	(287,292,000)	(101,644,000)
Proceeds from sale of other property, plant and equipment	140,000	—	—
Proceeds from sale of oil and gas properties	63,590,000	1,384,000	304,000
Advances on note receivable to related party	—	(3,182,000)	(2,877,000)
Contributions to equity method investments	(147,307,000)	(34,621,000)	(1,244,000)
Distributions from equity method investments	820,000	870,000	565,000
Net cash used in investing activities	(840,579,000)	(323,248,000)	(105,315,000)
Cash flows from financing activities:			
Principal payments on borrowings	(158,639,000)	(97,634,000)	(52,711,000)
Borrowings on line of credit	158,500,000	48,000,000	52,200,000
Proceeds from bond issuance	296,835,000	—	—
Debt issuance costs and loan commitment fees	(9,175,000)	(981,000)	(1,144,000)
Proceeds from issuance of common stock, net of offering costs, and exercise of stock options	427,091,000	307,154,000	21,879,000
Net cash provided by financing activities	714,612,000	256,539,000	20,224,000

Net increase in cash and cash equivalents	73,191,000	91,429,000	744,000
Cash and cash equivalents at beginning of period	93,897,000	2,468,000	1,724,000
Cash and cash equivalents at end of period	$167,088,000	$93,897,000	$2,468,000
Supplemental disclosure of cash flow information:			
Interest payments	$1,461,000	$991,000	$1,949,000
Income tax payments	$261,000	$1,000	$40,000
Supplemental disclosure of non-cash transactions:			
Capitalized stock based compensation	$1,875,000	$515,000	$197,000
Asset retirement obligation capitalized	$2,195,000	$1,390,000	$1,328,000
Foreign currency translation gain (loss) on investment in Grizzly Oil Sands ULC	$1,355,000	$(855,000)	$1,313,000
Foreign currency translation gain (loss) on note receivable—related party	$—	$(1,085,000)	$942,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2012, 2011 AND 2010
(Amounts rounded to nearest thousand)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Gulfport Energy Corporation ("Gulfport" or the "Company") is an independent oil and gas exploration, development and production company with its principal properties located in the Louisiana Gulf Coast, the Utica Shale in Eastern Ohio and in Western Colorado in the Niobrara Formation and has investments in companies operating in the Permian Basin in West Texas, Canada and Thailand.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the statement of cash flows.

Principles of Consolidation

The consolidated financial statements include the Company and its wholly owned subsidiaries, Grizzly Holdings Inc., Jaguar Resources LLC, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Westhawk Minerals LLC and Puma Resources, Inc. All intercompany balances and transactions are eliminated in consolidation.

Accounts Receivable

The Company's accounts receivable—oil and gas primarily are from companies in the oil and gas industry. The majority of its receivables are from two purchasers of the Company's oil and gas. Credit is extended based on evaluation of a customer's payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts 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 customer's current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2012 and December 31, 2011.

Oil and Gas Properties

The Company uses the full cost method of accounting for oil and gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and gas properties, are capitalized. Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for 2012, 2011 and 2010, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company's oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required.

Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and gas reserves. Oil and gas properties not subject to amortization consist of the cost of unproved leaseholds and totaled $626,295,000 and $138,623,000 at

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December 31, 2012 and December 31, 2011, respectively. These costs are reviewed quarterly by management for impairment. If impairment has occurred, the portion of cost in excess of the current value is transferred to the cost of oil and gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by Gulfport and other operators, the terms of oil and gas leases not held by production, and available funds for exploration and development.

The Company accounts for its abandonment and restoration liabilities under FASB ASC Topic 410, "Asset Retirement and Environmental Obligations" ("FASB ASC 410"), which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is included in capitalized costs and depreciated consistent with depletion of reserves. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Other Property and Equipment

Depreciation of other property and equipment is provided on a straight-line basis over the estimated useful lives of the related assets, which range from 3 to 30 years.

Foreign Currency

The U.S. dollar is the functional currency for Gulfport's consolidated operations. However, the Company has an equity investment in a Canadian entity whose functional currency is the Canadian dollar. The assets and liabilities of the Canadian investment are translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates. Canadian income and expenses are translated at average rates for the periods presented. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders' equity. The following table presents the balances of the Company's cumulative translation adjustments included in accumulated other comprehensive income.

December 31, 2009	$696,000
December 31, 2010	$2,952,000
December 31, 2011	$1,087,000
December 31, 2012	$2,442,000

Net Income per Common Share

Basic net income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution that could occur if options or other contracts to issue common stock were exercised or converted into common stock. Potential common shares are not included if their effect would be anti-dilutive. Calculations of basic and diluted net income per common share are illustrated in Note 12.

Income Taxes

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

The Company is subject to U.S. federal income tax as well as income tax of multiple jurisdictions. The Company's 1998 – 2012 U.S. federal and state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2012, the Company has no unrecognized tax benefits that would have a material impact on the effective rate. The Company recognizes interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. For the year ended December 31, 2012, there is no interest or penalties associated with uncertain tax positions in the Company's consolidated financial statements.

Revenue Recognition

Gas revenues are recorded in the month produced and delivered to the purchaser using the entitlement method, whereby any production volumes received in excess of the Company's ownership percentage in the property are recorded as a liability. If less than Gulfport's entitlement is received, the underproduction is recorded as a receivable. At December 31, 2012, the Company had a gas imbalance liability of approximately $354,000. At December 31, 2011, the Company had no imbalances. Oil revenues are recognized when ownership transfers, which occurs in the month produced.

Investments—Equity Method

Investments in entities greater than 20% and less than 50% are accounted for under the equity method. Under the equity method, the Company's share of investees' earnings or loss is recognized in the statement of operations. In accordance with FASB ASC 825, "Financial Instruments," the Company has elected the fair value option of accounting for its equity method investment in Diamondback Energy Inc.'s ("Diamondback") stock. At the end of each reporting period, the quoted closing market price of Diamondback's stock is multiplied by the total shares owned by the Company and the resulting gain or loss is recognized in (income) loss from equity method investments in the consolidated statements of operations.

The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company recognizes an impairment provision. There was no impairment of equity method investments at December 31, 2012 or 2011.

Accounting for Stock-Based Compensation

The Company accounts for stock-based compensation in accordance with the provisions of FASB ASC Topic 718, "Compensation—Stock Compensation" ("FASB ASC 718"). FASB ASC 718 requires share-based payments to employees, including grants of employee stock options and restricted stock, to be recognized as equity or liabilities at the fair value on the date of grant and to be expensed over the applicable vesting period. The vesting periods for the options range between three to five years and have a maximum contractual term of ten years. The vesting periods for restricted shares range between three to five years with either quarterly or annual vesting installments.

Accounting for Derivative Instruments and Hedging Activities

The Company may seek to reduce its exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. The Company follows the provisions of FASB ASC 815, "Derivatives and Hedging" ("FASB ASC 815") as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value.

The Company estimates the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and the Company's realized prices, time to maturity and credit risk. The values reported in the consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ materially from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows there from, the amount and timing of asset retirement obligations, the realization of deferred tax assets and the realization of future net operating loss carryforwards available as reductions of income tax expense. The estimate of the Company’s oil and gas reserves is used to compute depletion, depreciation, amortization and impairment of oil and gas properties.

Reclassification

Certain reclassifications have been made to prior period financial statements to conform to current period presentation.

Recent Accounting Pronouncements

In February 2013, the FASB issued Accounting Standards Update ("ASU") No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income," which requires additional information about amounts reclassified out of accumulated other comprehensive income by component. This ASU requires the presentation, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, a cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. The requirements of this ASU are effective prospectively for reporting periods beginning after December 15, 2012 with early adoption permitted. The Company will adopt the provisions of this ASU for reporting periods in 2013 and does not expect the adoption of this ASU to have a material effect on its consolidated financial statements.

In May 2011, the FASB issued ASU No. 2011-04, “Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS,” which provides amendments to FASB ASC Topic 820, “Fair Value Measurements and Disclosure” (“FASB ASC 820”). The purpose of the amendments in this update is to create common fair value measurement and disclosure requirements between GAAP and IFRS. The amendments change certain fair value measurement principles and enhance the disclosure requirements. The amendments to FASB ASC 820 were effective for interim and annual periods beginning after December 15, 2011. Adoption of this ASU for reporting periods in 2012 had no impact on the Company's financial position or results of operations.

In June 2011, the FASB issued ASU 2011-05, “Comprehensive Income: Presentation of Comprehensive Income,” which provides amendments to FASB ASC Topic 220, “Comprehensive Income” (“FASB ASC 220”). The purpose of the amendments in this update is to provide a more consistent method of presenting non-owner transactions that affect an entity’s equity. The amendments eliminate the option to report other comprehensive income and its components in the statement of changes in 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. The amendments to FASB ASC 220 were effective for interim and annual periods beginning after December 15, 2011 and should be applied retrospectively. The Company adopted this ASU for reporting periods in 2012 and reports the components of net income and the components of other comprehensive income in two separate but consecutive statements. Adoption of this ASU had no impact on the Company's financial position or results of operations.

2. ACQUISITIONS

Beginning in February 2011, the Company entered into agreements to acquire certain leasehold interests located in the Utica Shale in Ohio. Certain of the agreements also grant the Company an exclusive right of first refusal for a period of six months on certain additional tracts leased by the seller. Affiliates of Gulfport initially participated with the Company on a 50/50 basis in the acquisition of all leases described above. On December 17, 2012, Gulfport entered into a definitive agreement to purchase approximately 30,000 net acres in the Utica Shale in Eastern Ohio for approximately $302.0 million. On December 19, 2012, the parties amended that agreement to provide for Gulfport's acquisition of approximately 7,000 additional net acres for approximately $70.0 million, resulting in a total purchase price of approximately $372.0 million, subject to certain adjustments. This transaction closed on December 24, 2012. At closing, approximately $53.9 million of the purchase price was placed in escrow pending completion of title review after the closing. The transaction, which increased Gulfport's leasehold interests in the Utica Shale to approximately 137,000 gross (106,000 net) acres, excluded 14 existing wells, along with certain acreage surrounding each well. Gulfport will continue to serve as operator of its acreage in the Utica Shale. Gulfport funded this acquisition with a portion of the net proceeds from its common stock offering that closed on December 24, 2012. The Company received aggregate net proceeds (including the net proceeds from the partial exercise of the underwriters' over-allotment option) of approximately $427.9 million from this equity offering, as discussed below in Note 8. As of December 31, 2012, Gulfport has paid a total of $619.6 million for its Ohio acreage.

3. ACCOUNTS RECEIVABLE—RELATED PARTIES

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Included in the accompanying consolidated balance sheets for the years ended December 31, 2012 and 2011, are amounts receivable from related parties of the Company. These receivables consist primarily of amounts billed by the Company to related parties as operator of such parties' Colorado and Ohio oil and gas properties. At December 31, 2012 and 2011, these receivables totaled $34,848,000 and $4,731,000, respectively.

The Company is a party to administrative service agreements with Stampede Farms LLC ("Stampede"), Everest Operations Management LLC ("Everest") and Tatex Thailand III, LLC ("Tatex III"), which agreements were each entered into effective March 1, 2008. Under these agreements, the Company’s services include professional and technical support and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements may be cancelled (1) by the Company with at least 60 days prior written notice, (2) by the counterparty at any time with at least 30 days prior written notice to the Company and (3) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach. The Company did not provide services under any of these agreements in 2010, 2011 or 2012 and received no reimbursements thereunder. Each of Stampede, Everest and Tatex III is controlled by Wexford Capital LP ("Wexford"). Charles E. Davidson is the Chairman and Chief Investment Officer of Wexford and he beneficially owned approximately 13.3% and less than 1% of the Company’s outstanding common stock as of December 31, 2011 and September 28, 2012, respectively.

For the years ended December 31, 2011 and 2010, the Company was reimbursed approximately $66,000 and $20,000, respectively, by Orange Leaf Holdings, LLC, an affiliate of Gulfport, for office space which is included in other income (expense) in the consolidated statements of operations.

Effective July 1, 2008, the Company entered into an acquisition team agreement with Everest to identify and evaluate potential oil and gas properties in which the Company and Everest or its affiliates may wish to invest. Upon a successful closing of an acquisition or divestiture, the party identifying the acquisition or divestiture is entitled to receive a fee from the other party and its affiliates, if applicable, participating in such closing. The fee is equal to 1% of the party’s proportionate share of the acquisition or divestiture consideration. The agreement may be terminated by either party upon 30 days notice. Affiliates of Everest were billed approximately $1,087,000 and $1,184,000 under this acquisition team agreement during the years ended December 31, 2012 and 2011, respectively, which amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations. No amounts were reimbursed under the acquisition team agreement for the year ended 2010.

Effective April 1, 2010, the Company entered into an area of mutual interest agreement with Windsor Niobrara LLC (“Windsor Niobrara”), an entity controlled by Wexford, to jointly acquire oil and gas leases on certain lands located in Northwest Colorado for the purpose of exploring, exploiting and producing oil and gas from the Niobrara Formation. The agreement provides that each party must offer the other party the right to participate in such acquisitions on a 50%/50% basis. 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. In connection with this agreement, Gulfport and Windsor Niobrara also entered into a development agreement, effective as of April 1, 2010, pursuant to which the Company and Windsor Niobrara agreed to jointly develop the contract area, and Gulfport agreed to act as the operator under the terms of a joint operating agreement.

4. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2012 and 2011 are as follows:

	December 31,	
	2012	2011
Oil and natural gas properties	$1,611,090,000	$1,035,754,000
Office furniture and fixtures	4,476,000	3,692,000
Building	3,926,000	4,049,000

Land	260,000	283,000
Total property and equipment	1,619,752,000	1,043,778,000
Accumulated depletion, depreciation, amortization and impairment	(665,884,000)	(575,142,000)
Property and equipment, net	$953,868,000	$468,636,000

No impairment of oil and natural gas properties was required under the ceiling test for the years ended