

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

FORM 10-K

(Mark One)

ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
OR

TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF 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
(State or Other Jurisdiction of
Incorporation or Organization)
14313 North May Avenue, Suite 100
Oklahoma City, Oklahoma
(Address of Principal Executive Offices)

73-1521290
(IRS Employer
Identification Number)

73134
(Zip Code)

(405) 848-8807

(Registrant 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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (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 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.

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 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

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of June 30, 2014, based on the closing price of the common stock on the NASDAQ Global Select Market on June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter (\$62.80 per share), was \$5,369,083,865.

As of February 20, 2015, 85,684,604 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation's Proxy Statement for the 2015 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,” “intends,” “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.

PART I

ITEM 1. BUSINESS

General

We are an independent oil and natural gas exploration and production company focused on the exploration, exploitation, acquisition and production of natural gas, natural gas liquids and crude oil in the United States. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as development and exploratory drilling opportunities on high potential conventional and unconventional oil and natural gas prospects. Our principal properties are located in the Utica Shale primarily in Eastern Ohio and along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields. In addition, we have producing properties in the Niobrara Formation of Northwestern Colorado and the Bakken Formation. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, and interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. Until November 2014, we held an equity interest in Diamondback Energy, Inc., or Diamondback, a NASDAQ Global Select Market listed company to which we contributed our Permian Basin oil and natural gas interests in October 2012 immediately prior to Diamondback's initial public offering, or the Diamondback IPO. At December 31, 2014, we did not own any shares of Diamondback. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

As of February 13, 2015, we held acquired leasehold interests in approximately 188,000 gross (184,000 net) acres in the Utica Shale primarily in Eastern Ohio, including approximately 8,200 net acres acquired from Rhino Exploration LLC in the first quarter of 2014. We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of December 31, 2014, had spud 151 gross wells, 101 of which were completed and were producing. In 2014, we spud 85 gross (67.2 net) wells, of which 36 were completed as producing wells, two were non-productive and, as of December 31, 2014, 41 were in various stages of completion and six were still being drilled. We commenced sales from 63 gross wells (47.4 net wells) in the Utica Shale during 2014. During 2015 (through February 13, 2015), we had spud five gross (four net) wells. As of February 13, 2015, three of these wells were in various stages of completion and two were still drilling. In addition, 110 gross (13.3 net) wells were drilled by other operators on our Utica Shale acreage during 2014.

We currently intend to drill 46 to 52 gross (28 to 32 net) horizontal wells, and commence sales from 49 to 53 gross (42 to 46 net) horizontal wells on our Utica Shale acreage in 2015 for an estimated aggregate cost of \$400.0 million to \$430.0 million. We currently anticipate 11 to 16 gross (four to six net) horizontal wells will be drilled, and sales commenced from 50 to 64 gross (seven to nine net) horizontal wells, by other operators on our Utica Shale acreage during 2015 for an estimated cost of \$125.0 million to \$140.0 million.

Aggregate net production from our Utica Shale acreage during the three months ended December 31, 2014 was approximately 32,513 net million cubic feet of natural gas equivalent, or MMcfe, or 353.4 MMcfe per day, of which 80% was from natural gas and 20% was from oil and natural gas liquids, or NGLs. During January 2015, our average daily net production from the Utica Shale was approximately 345.6 MMcfe, of which 79% was from natural gas and 21% was from oil and NGLs.

In 2014, at our WCBB field, we recompleted 91 wells and spud 29 wells. Of the 29 new wells spud at WCBB in 2014, 21 were completed as producing wells, five were non-productive and, at year end, three were waiting on completion. In the fourth quarter of 2014, production at WCBB was approximately 1,810 MMcfe, or an average of 19.7 MMcfe per day, 100% of which was from oil. During January 2015, our average net daily production at WCBB was approximately 19.0 MMcfe, 100% of which was from oil.

In 2014, at our East Hackberry field, we recompleted 68 wells and spud 15 wells. All of the 15 new wells spud at East Hackberry during 2014 were completed as producing wells. In the fourth quarter of 2014, net production at East Hackberry was approximately 640 MMcfe, or an average of 7.0 MMcfe per day, of which 82% was from oil and 18% was from natural gas. During January 2015, our average net daily production at East Hackberry was approximately 10.1 MMcfe, of which 91% was from oil and 9% was from natural gas.

In 2014, at our West Hackberry field, we recompleted two wells and spud one well which was productive. In the fourth quarter of 2014, net production at West Hackberry was approximately 66.3 MMcfe, or an average of 720.4 Mcfe per day, of which 91% was from oil and 9% was from natural gas. During January 2015, our average net daily production at West Hackberry was approximately 589.2 Mcfe, of which 97% was from oil and 3% was from natural gas.

We currently estimate our 2015 activities in our Southern Louisiana fields to be approximately \$20.0 million to \$25.0 million in aggregate for maintenance capital activities.

Effective as of April 1, 2010, we acquired our initial leasehold interests in the Niobrara Formation in Northwestern Colorado and, as of December 31, 2014, we held leases for approximately 5,900 net acres. During the year ended December 31, 2014, there were no wells spud on our Niobrara Formation acreage. In the fourth quarter of 2014, net production from our Niobrara Formation acreage was approximately 27.4 MMcfe, or an average of 297.3 Mcfe per day, 100% of which was from oil. During January 2015, our average net daily production from our Niobrara Formation acreage was approximately 326.3 Mcfe, 100% of which was from oil. During 2015, we currently do not anticipate drilling any wells in the Niobrara Formation.

As of December 31, 2014, we held approximately 864 net acres in the Bakken Formation of Western North Dakota and Eastern Montana with interests in 18 wells and overriding royalty interests in certain existing and future wells. In the fourth quarter of 2014, our net production from this acreage was approximately 74.4 MMcfe, or an average of 808.8 Mcfe per day, of which 93% was from oil and natural gas liquids and 7% was from natural gas. During January 2015, our average daily net production from our Bakken Formation acreage was approximately 609.0 Mcfe, of which 87% was from oil and 13% was from natural gas.

As of December 31, 2014, we had sold all of our shares of common stock of 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 the Diamondback IPO. See Notes 4 and 5 to our consolidated financial statements included elsewhere in this report for additional information regarding our prior investment in Diamondback.

We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. As of December 31, 2014, Grizzly had approximately 830,000 net acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. Grizzly has three oil sands projects in various stages of development. Grizzly commenced commercial production from its Algar Lake Phase 1 steam-assisted gravity drainage, or SAGD, oil sand project during the second quarter of 2014 and has received regulatory approval for up to 11,300 barrels per day of bitumen production. Grizzly produced approximately 1,400 barrels of bitumen per day at its Algar Lake SAGD project during the fourth quarter of 2014. Grizzly has announced that it expects bitumen production to reach its 6,000 barrels per day peak production rate by the fourth quarter of 2015. In the first quarter of 2012, Grizzly acquired the May River property comprising approximately 47,000 acres. An initial 12,000 barrel per day development application was filed with the regulatory authorities in the fourth quarter of 2013, covering the eastern portion of the May River lease. The development application continues to move through the regulatory process and is expected to be approved by mid-2015. In the first quarter of 2014, a 2-D seismic program covering approximately 83 kilometers was completed to more fully define the resource over the remaining lease beyond the development application area. At the Thickwood thermal project, a development application for a 12,000 barrel per day oil sands project was filed in the fourth quarter of 2012. Since then, the Alberta Energy Regulator, or AER, announced it is implementing a policy for future regulatory requirements for reservoir containment in shallow SAGD areas, which impacts the Thickwood application. Additional work to advance the Thickwood application will be required and is expected to be addressed once the May River development approval is received. Grizzly has also developed delineation drilling, seismic and regulatory work plans at its Cadotte, Peace River property. Grizzly is pursuing a rail marketing strategy to ensure consistent and flexible access to premium markets for its production, including its Windell truck to rail terminal located near Conklin, Alberta, which commenced transloading blended bitumen production from Algar Lake on to rail cars for delivery to the US Gulf Coast markets in the second quarter of 2014.

We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II. Tatex II, a privately held entity, holds an 8.5% interest in APICO, 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. Tatex III owns a concession covering approximately 245,000 acres in Southeast Asia. In 2009, Tatex III completed a 3-D seismic survey on this concession. Between 2010 and 2013, three wells were drilled on Tatex III's concession. Each of the wells lacked sufficient permeability to produce in commercial quantities. Tatex III plans to allow the concession to expire in 2015.

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 2013, we participated in the formation of Stingray Energy Services LLC, or Stingray Energy, with an initial ownership interest of 50%. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. In 2012, we participated in the formation of Stingray Pressure Pumping LLC, or Stingray Pressure, Stingray Cementing LLC, or

Stingray Cementing, and Stingray Logistics LLC, or Stingray Logistics, with an initial ownership interest in each entity of 50%. These entities provide well completion and other well services. In 2012, we also participated in the formation of Blackhawk Midstream LLC, or Blackhawk, and Timber Wolf Terminals, LLC, or Timber Wolf, with an initial ownership interest of 50% in each entity. Blackhawk coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage and Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. Also in 2012, we acquired a 22.5% equity interest in Windsor Midstream LLC, or Midstream, which owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011 and 2012, we acquired an aggregate 40% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates drilling rigs and related equipment. Also in 2011, we acquired a 25% interest in Muskie Proppant LLC, or Muskie, which is engaged in the processing and sale of hydraulic fracturing grade sand. In 2014, we acquired a 25% equity interest in Sturgeon Acquisitions LLC, or Sturgeon. Sturgeon owns and operates sand mines that produce hydraulic fracturing grade sand. In the fourth quarter of 2014, we contributed our investments in Stingray Pressure, Stingray Logistics, Bison and Muskie to Mammoth Energy Partners LP, or Mammoth, in exchange for a 30.5% limited partner interest in this newly formed limited partnership. Mammoth has filed a registration statement on Form S-1 with the SEC in connection with a contemplated initial public offering, which it intends to pursue in 2015 subject to market conditions. See Note 5 to our consolidated financial statements included elsewhere in this report for additional information regarding these investments.

As of December 31, 2014, we had 933.6 Bcfe of proved reserves with a present value of estimated future net revenues, discounted at 10%, or PV-10, of approximately \$1.8 billion and associated standardized measure of discounted future net cash flows of approximately \$1.4 billion, excluding reserves attributable to our interests in 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.

Principal Oil and Natural Gas Properties

The following table presents certain information as of December 31, 2014 reflecting our net interest in our principal producing oil and natural gas properties in the Utica Shale primarily in Eastern Ohio, along the Louisiana Gulf Coast, in the Niobrara Formation in Northwestern Colorado and in the Bakken Formation in Western North Dakota and Eastern Montana.

Field	NRI/WI (1) Percentages	Productive Wells (2)		Non-Productive Wells		Developed Acreage (3)		Proved Reserves			
		Gross	Net	Gross	Net	Gross	Net	Gas MMcf	Oil MBbls	NGLs MBbls	Total MMcfe
		Utica Shale (4)	34.52/41.46	195	80.85	3	2.66	21,652	19,340	716,905	5,412
West Cote Blanche Bay Field (5)	80.108/100	123	123	185	185	5,668	5,668	1,318	2,968	—	19,127
E. Hackberry Field (6)	80.945/100	39	39	107	107	3,931	3,931	516	469	—	3,331
W. Hackberry Field	79.167/100	6	6	7	7	1,192	1,192	—	402	—	2,413
Niobrara Formation	39.83/47.85	6	3	—	—	3,502	1,751	135	124	—	878
Bakken Formation (4)	1.51/1.83	18	0.3	—	—	1,862	163	108	121	—	834
Overrides/Royalty Non-operated	Various	384	0.42	—	—	—	—	24	1	—	33
Total		771	252.57	302	301.66	37,807	32,045	719,006	9,497	26,268	933,598

- (1) Net Revenue Interest (NRI)/Working Interest (WI) for producing wells.
- (2) Includes one gross and net well at WCBB that is producing intermittently.
- (3) Developed acres are acres spaced or assigned to productive wells. Approximately 16% of our acreage is developed acreage and has been held by production.
- (4) Includes NRI/WI from wells that have been drilled or in which we have elected to participate. Includes 94 gross (7.57 net) wells drilled by other operators on our acreage.
- (5) 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).
- (6) NRI shown is for producing wells.

Utica Shale (primarily in Eastern Ohio)

Location and Land

As of December 31, 2014, we held leasehold interests in approximately 185,000 gross (180,000 net) acres in the Utica Shale.

Area History

The Ohio Department of Natural Resources reported that in the Utica Shale in Ohio, as of February 7, 2015, there were 740 producing horizontal wells, 335 horizontal wells that had been drilled but were not yet completed or connected to a pipeline, 273 horizontal wells that were being drilled and an additional 451 horizontal wells that had been permitted.

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.

Recently, the application of horizontal drilling, combined with multi-staged hydraulic fracturing to create permeable flow paths from shale units into wellbores, has resulted in increased drilling activity and production in the Devonian-age Marcellus Shale and the Ordovician-age Utica 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 which extend across much of the Appalachian Basin region.

The Utica Shale is estimated to be thicker and more geographically extensive than the Marcellus Shale. The 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 this area, the Utica Shale ranges in thickness from less than 100 feet to over 500 feet. 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.

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. Operators in the Utica play continue to refine completions techniques to optimize productivity.

Facilities

There are standard land oil and gas processing facilities in the Utica Shale. Our facilities located at well site pads include storage tank batteries, oil/gas/water separation equipment, vapor recovery units, line heaters, compression emission control devices and applicable metering.

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, 2014, had spud 151 gross wells, 101 of which were completed and were producing. In 2014, we spud 85 gross (67.2 net) wells, of which 36 were completed and are productive, two were non-productive and, as of December 31, 2014, 41 were in various stages of completion and six were still being drilled. During 2015 (through February 13, 2015), we had spud five gross (four net) wells during 2015 of which three were in various stages of completion and two were still drilling. In addition, 110 gross (13.3 net) wells were drilled by other operators on our Utica Shale acreage during 2014.

We currently intend to drill 46 to 52 gross (28 to 32 net) horizontal wells, and commence sales from 49 to 53 gross (42 to 46 net) horizontal wells, on our Utica Shale acreage in 2015 and anticipate 11 to 16 gross (four to six net) horizontal wells will be drilled, and sales commenced from 50 to 64 gross (seven to nine net) horizontal wells, by other operators on our Utica Shale

acreage during 2015. As of February 25, 2015, we had four operated horizontal rigs drilling in the play, but plan to release one of these rigs by the end of the first quarter of 2015.

Production Status

Aggregate net production from the Utica Shale during the three months ended December 31, 2014 was approximately 32,513 MMcfe, or 353.4 MMcfe per day, of which 80% was from natural gas and 20% was from oil and NGLs. During January 2015, our average daily net production from the Utica Shale was approximately 345.6 MMcfe, of which 79% was from natural gas and 21% was from oil and NGLs. The slight decrease in January 2015 production was the result of adverse winter weather conditions, partially offset by our 2014 drilling activities.

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 1,077 wells drilled as of December 31, 2014, 973 were completed as producing wells. From the date of our acquisition of WCBB in 1997 through December 31, 2014, we drilled 265 new wells, 233 of which were productive, for an 88% success rate. As of December 31, 2014, estimated field cumulative gross production was 196.8 MMBOE and 237.0 Bcf of gas. Of the 1,077 wells drilled in WCBB as of December 31, 2014, 122 were producing, 185 were shut-in, one was producing intermittently, one was waiting on completion and six were being used as salt water disposal wells. The other 762 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 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 1,077 wells that had been drilled in the field as of December 31, 2014, 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.

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 2014, we recompleted 91 gross and net wells and spud 29 gross and net wells at WCBB. Of the 29 new wells spud at WCBB in 2014, 21 were completed as producers, five were non-productive and, at year end, three were waiting on completion. As of February 13, 2015, we had recompleted seven wells during 2015 in our WCBB field. Of the 29 wells drilled in 2014, 22 were considered deep wells. The 21 productive wells, with total depths ranging from 2,500 to 10,501 feet, have approximately 894 feet of aggregate apparent net pay.

Production Status

In the fourth quarter of 2014, our production at WCBB was approximately 1,810 net MMcfe, or an average of 19.7 MMcfe per day, 100% of which was from oil. During January 2015, our average net daily production at WCBB was approximately 19.0 MMcfe, 100% of which was from oil. The slight decrease in average net daily production in January 2015 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 80.945% average NRI) in certain producing oil and natural gas properties situated in the East Hackberry field. As of December 31, 2014, 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 through 2014 was over 4,037 MBOE and 331.8 Bcf of casinghead gas production. A total of 269 wells have been drilled on our portion of the field. As of December 31, 2014, 39 wells had daily production, 107 were shut-in and three had been converted to salt water disposal wells. The remaining 120 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, five natural gas compressors, dehydration units and salt water disposal systems.

Recent and Future Activity

During 2014 at East Hackberry, we recompleted 68 gross and net wells and drilled 15 gross and net land wells. All of the 15 wells drilled during 2014 were completed as producing wells. As of February 13, 2015, we had recompleted 11 wells during 2015 in our East Hackberry field.

Production Status

In the fourth quarter of 2014, our net production at East Hackberry was approximately 640 MMcfe, or an average of 7.0 MMcfe per day, 82% of which was from oil and 18% of which was from natural gas. During January 2015, our average net daily production at East Hackberry was approximately 10.1 MMcfe, of which 91% was from oil and 9% was from natural gas. The increase in production in 2015 is a result of our 2014 drilling and recompletion 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 79.167% 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 2014 was 426 MBOE and 140 Bcf of natural gas. As of December 31, 2014, 41 wells had been drilled on our portion of West Hackberry. As of December 31, 2014, six of such wells were producing, seven were shut-in and one had been converted to a saltwater disposal well. The remaining 27 wells have been plugged and abandoned.

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.

Recent and Future Activity

During 2014 at West Hackberry, we recompleted two gross and net wells and drilled one gross and net well which was productive. As of February 13, 2015, no new wells had been drilled in our West Hackberry field.

Production Status

In the fourth quarter of 2014, our net production at West Hackberry was approximately 66.3 MMcfe, or an average of 720.4 Mcfe per day, of which 91% was from oil and 9% was from natural gas. During January 2015, our average net daily production at West Hackberry was approximately 589.2 Mcfe, of which 97% was from oil and 3% was from natural gas.

Facilities

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

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, as of December 31, 2014, we held leases for approximately 5,900 net acres. In 2014, no wells were spud on our Niobrara Formation acreage.

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 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 area's 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 to 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 2014, our net production from our Niobrara Formation acreage was approximately 27.4 MMcfe, or an average of 297.3 Mcfe per day, 100% of which was from oil. During January 2015, our average daily net production from our Niobrara Formation acreage was approximately 326.3 Mcfe, 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 2015.

Bakken Formation

Location and Land

The Bakken Formation is located in the Williston Basin areas of Western North Dakota and Eastern Montana. As of December 31, 2014, we held approximately 864 net acres, interests in 18 wells and an overriding royalty interests in certain existing and future wells.

Production Status

In the fourth quarter of 2014, our net production from our Bakken Formation acreage was approximately 74.4 MMcfe, or an average of 808.8 Mcfe per day, of which 93% was from oil and NGLs and 7% was from natural gas. During January 2015, our average net daily production from this acreage was approximately 609.0 Mcfe, of which 87% was from oil and 13% 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.

Recent and Future Activities

Two gross (.01 net) wells were drilled on our Bakken Formation acreage in 2014. As of February 13, 2015, no new wells had been drilled on our Bakken Formation acreage in 2015.

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, 2014:

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

Grizzly Oil Sands. We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. As of December 31, 2014, Grizzly had approximately 830,000 net acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. Grizzly has three oil sands projects in various stages of development. Grizzly commenced commercial production from its Algar Lake Phase 1 steam-assisted gravity drainage, or SAGD, oil sand project during the second quarter of 2014 and has received regulatory approval for up to 11,300 barrels per day of bitumen production. Grizzly produced approximately 1,400 barrels of bitumen per day at its Algar Lake SAGD project during the fourth quarter of 2014. Grizzly has announced that it expects bitumen production to reach its 6,000 barrels per day peak production rate by the fourth quarter of 2015. In the first quarter of 2012, Grizzly acquired the May River property comprising approximately 47,000 acres. An initial 12,000 barrel per day development application was filed with the regulatory authorities in the fourth quarter of 2013, covering the eastern portion of the May River lease. The development application continues to move through the regulatory process and is expected to be approved by mid-2015. In the first quarter of 2014, a 2-D seismic program covering approximately 83 kilometers was completed to more fully define the resource over the remaining lease beyond the development application area. At the Thickwood thermal project, a development application for a 12,000 barrel per day oil sands project was filed in the fourth quarter of 2012. Since then, the Alberta Energy Regulator, or AER, announced it is implementing a policy for future regulatory requirements for reservoir containment in shallow SAGD areas, which impacts the Thickwood application. Additional work to advance the Thickwood application will be required and is expected to be addressed once the May River development approval is received. Grizzly has also developed delineation drilling, seismic and regulatory work plans at its Cadotte, Peace River property. Grizzly is pursuing a rail marketing strategy to ensure consistent and flexible access to premium markets for its production, including its Windell truck to rail terminal located near Conklin, Alberta, which commenced transloading blended bitumen production from Algar Lake on to rail cars for delivery to the US Gulf Coast markets in the second quarter of 2014.

Thailand. We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatem II. Tatem II, a privately held entity, holds an 8.5% interest in 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. Our investment is accounted for on the equity method. Tatem 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 2014, net gas production was approximately 105 MMcf per day and condensate production was 415 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 Tatem 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 Tatem II's investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information.

We own a 17.9% ownership interest in Tatem Thailand III, LLC, or Tatem III. Tatem III owns a concession covering approximately 245,000 acres in Southeast Asia. In 2009, Tatem III completed a 3-D seismic survey on this concession. Between 2010 and 2013, three wells were drilled on this concession. Each of the wells lacked sufficient permeability to produce in commercial quantities. Tatem III plans to allow the concession to expire in 2015.

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 2013, we participated in the formation of Stingray Energy with an initial ownership interest of 50%. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. In 2012, we participated in the formation of Stingray Pressure, Stingray Cementing, and Stingray Logistics, with an initial ownership interest in each entity of 50%. These entities provide well completion and other well services. In 2012, we also participated in the formation of Blackhawk and Timber Wolf, with an initial ownership interest of 50% in each entity. Blackhawk coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage and Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. Also in 2012, we acquired a 22.5% equity interest in Midstream which owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011 and 2012, we acquired an aggregate 40% equity interest in Bison, which owns and operates drilling rigs and related equipment. Also in 2011, we acquired a 25% interest in Muskie, which is engaged in the processing and sale of hydraulic fracturing grade sand. In 2014, we acquired a 25% equity interest in Sturgeon. Sturgeon owns and operates sand mines that produce hydraulic fracturing grade sand. In the fourth quarter of 2014, we contributed our investments in Stingray Pressure, Stingray Logistics, Bison and Muskie to Mammoth in exchange for a 30.5% limited partner interest in this newly formed limited partnership. Mammoth has filed a registration statement on Form S-1 with the SEC in connection with a contemplated initial public offering which it intends to pursue in 2015 subject to market conditions. See Note 5 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These 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.

Marketing and Customers

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 Southern Louisiana 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 transportation charges. Shell is the purchaser of our Utica Shale oil and pays us WTI less a differential. MarkWest Utica currently markets our Utica Shale NGLs and remits to us a weighted average selling price less a marketing fee. We have NAESBs in place with various purchasers for our Utica Shale natural gas production. In 2014, our Utica Shale natural gas and natural gas liquids were sold under monthly, seasonal and long term contracts and, as needed, through daily trades. The majority of purchases are transacted at the tailgate of the plants with available pricing based on Platts Gas Daily - Appalachian - Dominion South Point (Dominion Eastern and Dominion Transmission) or Texas Eastern M2 Zone when sold in the Utica Basin. To maintain flow assurance and price stability, and as discussed under "- Transportation and Takeaway Capacity," we have entered into agreements to transport a portion of our natural gas production out of the Utica Basin. These agreements have pricing based on the appropriate delivery point less transportation charges and fuel.

During the year ended December 31, 2014, we sold approximately 99% of our oil production to Shell, 100% of our natural gas liquids production to MarkWest Utica and 40%, 32% and 19% of our natural gas production to BP, DTE Energy Trading, Inc. and Hess, respectively. During the year ended December 31, 2013, we sold approximately 99% of our oil production to Shell, 100% of our natural gas liquids production to MarkWest Utica and 32%, 31% and 17% of our natural gas production to Sequent Energy Management, L.P., Hess and Interstate Gas Supply, Inc., respectively. During the year ended December 31, 2012, we sold approximately 92% and 8% of our oil production to 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.

As of December 31, 2014, we had approximately 218,000 MMBtu per day of firm sales contracted with third parties. Of these sales, 33,000 MMBtu per day, 5,000 MMBtu per day, 30,000 MMBtu per day, 50,000 MMBtu per day, 50,000 MMBtu per day and 50,000 MMBtu per day expire in 2015, 2016, 2017, 2018, 2019 and 2022, respectively.

Transportation and Takeaway Capacity

In Ohio, as of December 31, 2014, we had entered into firm transportation contracts for 2015, 2016 and 2017 for an aggregate of approximately 619,000 MMBtu per day, 719,000 MMBtu per day and 719,000 MMBtu per day, respectively, and currently have agreements in place to transport and/or sell approximately 787,000 MMBtu per day of our gross Utica Shale gas production by year-end 2015. We continuously monitor the need to secure additional firm transportation contracts for incremental volumes from our Utica Shale acreage but expect additional contracts to be limited in 2015. Our primary long-haul firm transportation commitments include the following:

- 194,000 MMBtu per day of firm capacity on ANR Pipeline Company facilities, which began in 2014 and allows us to reach the Michigan, Chicago and Wisconsin natural gas markets,
- 200,000 MMBtu per day of firm capacity on Tennessee Gas Pipeline facilities beginning in April 2015 allowing access to Gulf Coast delivery points,
- 175,000 MMBtu per day of firm capacity on Rockies Express Pipeline facilities expected to begin in mid-2015 allowing additional connectivity to Gulf Coast and Midwest markets,
- 50,000 MMBtu per day of firm capacity on Texas Gas Transmission facilities expected to begin in 2016 allowing additional access to Gulf Coast delivery points, and
- 100,000 MMBtu per day of firm capacity on Energy Transfer's Rover Pipeline facilities beginning in late 2016/early 2017 allowing additional access to both Midwest and Gulf Coast delivery points.

Under firm transportation contracts, we are obligated to deliver minimum daily volumes or pay fees for any deficiencies in deliveries. We continue to actively identify and evaluate additional takeaway capacity to facilitate production growth in our Utica Basin position.

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.

We own interests in producing oil and natural gas properties located in the Utica Shale primarily in Eastern Ohio, along the Louisiana Gulf Coast and in 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 regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing 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 protection of the environment or occupational health and safety. Numerous governmental agencies, such as the U.S. Environmental Protection Agency, or the EPA, issue regulations that 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 earthen pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

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

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

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or the "Superfund" law, and analogous state laws, generally imposes strict and joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current owner or

operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed “responsible parties” may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such “hazardous substances” have been released.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the “Clean Water Act,” the Safe Drinking Water Act, the Oil Pollution Act, or OPA, and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on October 20, 2011, the EPA announced a schedule to develop pre-treatment standards for wastewater discharges produced by natural gas extraction from shale formations. The EPA stated that it will gather data, consult with the stakeholders, including ongoing consultation with the industry, and solicit public comment on a proposed rule for shale gas in early 2015. 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 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 the OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, on August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new emission controls for oil and natural gas production and processing operations, which regulations are discussed in more detail below 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. In December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other greenhouse gasses, or 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, including rules that regulate emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. In response to its endangerment finding, the EPA adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the “tailoring rule”) in May 2010, and it also became effective in January 2011. The tailoring rule established 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. On June 23, 2014, in *Utility Air Regulatory Group v. EPA*, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court’s decision in *Utility Air Regulatory Group v. EPA*. In its preliminary guidance, the EPA indicated that it will undertake a rulemaking action no later than December 31, 2015 to rescind any PSD permits issued under the portions of the tailoring rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted “no action assurance” indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. In November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011.

The EPA has continued to adopt GHG regulations applicable to other industries, such as the September 2013 proposed GHG rule that, if finalized, would set New Source Performance Standards, which we refer to as the NSP standards, for new coal-fired and natural-gas fired power plants. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility. In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions.

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

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

Endangered Species Act

Environmental laws such as the Endangered Species Act, as amended, or the ESA, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the U.S., and prohibits taking of endangered species. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Federal agencies are required to insure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. The U.S. Fish and Wildlife Service may identify, however, previously unidentified endangered or threatened species or may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species, which could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Occupational Safety and Health Act

We are also subject to the requirements of OSHA and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

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. We use hydraulic fracturing extensively in the development of our Utica Shale acreage. 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 in the past 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. In addition, on May 9, 2014, the EPA issued an Advance Notice of Proposed Rulemaking seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. The public comment period ended on September 19, 2014. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. Moreover, the EPA announced in 2011 that it was launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards in early 2015 that such wastewater must meet before being transported to a treatment plant. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

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

On August 16, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes NSP 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. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that will likely be responsive to some of these requests. For example, on September 23, 2013, the EPA published an amendment extending compliance dates for certain storage vessels. Also, on December 19, 2014, the EPA released final updates and clarifications to the NSP standards. In addition, on January 14, 2015, the EPA announced a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. In addition, the U.S. Department of the Interior, or DOI, published a revised proposed rule on May 24, 2013, that would update existing regulation for hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. The DOI announced its intent to finalize the rule in 2014, however, the final rule remains pending.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. 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 EPA is currently evaluating the potential impacts of hydraulic fracturing on drinking water resources, with results of the study anticipated to be available in March 2015. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the Securities and Exchange Commission, or 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 and local jurisdictions 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, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, in June 2012, Ohio's Governor signed legislation mandating chemical disclosure for hydraulic fracturing fluids, pre-drilling testing of water samples within 1,500 feet of a proposed horizontal well, and increased well operator liability insurance requirements. In addition, in April 2014, Ohio's Department of Natural Resources announced new permit conditions for drilling near faults or areas of past seismic activity. The Texas Railroad Commission, or RRC, and Louisiana Department of Natural Resources 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. Additionally, on October 28, 2014, the RRC adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. These searches are intended to determine the potential of earthquakes within a circular area of 100 square miles around a proposed new disposal well. The disposal well rule amendments, which became effective in Texas on November 17, 2014, also clarify the RRC's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. Also, in May 2013, the RRC adopted new rules, which became effective in January 2014, governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Effective August 27, 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 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, in 2013 and 2014, Colorado approved regulations that require well operators to test groundwater quality before and after drilling and to install emission controls to capture 95 percent of VOC and methane emissions. In addition, on May 16, 2013, the DOI issued a revised proposed 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.

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, state or local 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, state or local laws 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 states and some counties and municipalities in which we operate also regulate one or more of the following:

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

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratibility 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. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

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

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

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

State Regulation. 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 oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

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

Operational Hazards and Insurance

The oil and natural gas 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 natural 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. A loss not fully covered by insurance could have a material adverse effect 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 sudden and accidental pollution for the effects of onshore and offshore pollution on third parties arising from our operations as well as \$10.0 million of gradual pollution insurance coverage. For our offshore WCBB properties, we also have a \$38.0 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 \$12.6 million of business interruption coverage available after a 90 day waiting period. All of our insurance coverage includes deductibles of up to \$500,000 per occurrence (\$1.25 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.

We carry control of well insurance for all of our Utica Shale wells and several Southern Louisiana wells. We also require all of our third party vendors to sign master service agreements in which they agree to indemnify us for injuries and deaths of the service provider's employees as well as contractors and subcontractors hired by the service provider.

We have prepared and have in place spill prevention control and countermeasure plans for each of our principal facilities 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 secondary containment systems to capture potential releases. We also own additional spill kits with oil booms and absorbent pads that are readily available, if needed. In addition, we have emergency response companies on retainer. These companies specialize in the clean up of hydrocarbons as a result of spills, blow-outs and natural disasters, and are on call to us 24 hours a day, seven days a week when their services are needed. We pay these companies a retainer plus additional amounts when they provide us with clean up services. Our aggregate payments for the retainer and clean up services during 2014 and 2013 were approximately \$0.2 million and \$0.7 million, respectively. While these companies have been able to meet our service needs when required from time to time in the past, it is possible that the ability of one or more of them 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 areas in which we operate and the nature of our production, we believe other companies would be available to us in the event our primary remediation companies are unable to perform. To supplement our planning and operation activities in Ohio, we also actively manage an incident response planning program and coordinate with applicable state agency personnel on spills and releases. We also participate in Ohio's Emergency Planning and Community Right to Know Act (EPCRA) program, which includes reporting of various materials used or stored on-site as well as notification to state and local emergency response centers, such as local fire departments, for emergency planning purposes.

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 25,200 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 own an approximately 5,700 square foot office building in St. Clairsville, Ohio that serves as our Ohio headquarters. In addition, we lease approximately 4,275 square feet of office space in St. Clairsville, Ohio. Each of these properties is suitable and adequate for its use.

Employees

At December 31, 2014, we had 203 employees. An unrelated Louisiana well servicing company provides all necessary field personnel needed to operate the WCBB and the Hackberry fields.

Availability of Company Reports

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

Market conditions for oil and natural gas, and particularly the recent decline in prices for oil and natural gas, could adversely affect our revenue, cash flows, profitability, growth, production and the present value of our estimated reserves

Our revenues, cash flows, profitability, future rate of growth, production 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;
- 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. During the past six years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, has ranged from a low of \$34.03 per barrel, or Bbl, in February 2009 to a high of \$113.39 per Bbl in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of \$1.82 per MMBtu in April 2012 to a high of \$7.51 per MMBtu in January 2010. During 2014, WTI prices ranged from \$52.87 to \$100.54 per Bbl and the Henry Hub spot market price of natural gas ranged from \$2.89 to \$4.91 per MMBtu. On January 20, 2015, the WTI posted price for crude oil was \$46.47 per Bbl and the Henry Hub spot market price of natural gas was \$2.82 per MMBtu, representing decreases of 54% and 43%, respectively, from the high of \$100.54 per Bbl of oil and \$4.91 per MMBtu for natural gas during 2014. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. 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 activities are curtailed, 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. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

Concerns over 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 and the United States financial market have contributed to increased economic uncertainty and diminished expectations for the global economy. 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 global economy. These factors, combined with volatility in commodity prices, business and consumer confidence and unemployment rates, have precipitated an economic slowdown. 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, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, 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 development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

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. For example, we currently estimate our exploration and production capital expenditures for 2015 to be in the range of \$545.0 million to \$595.0 million and an additional \$85.0 million to \$95.0 million for acreage acquisitions in the Utica Shale.

Historically, we have financed capital expenditures primarily with cash flow from operations, the issuance of equity and debt 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 volume of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and

- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our credit facility.

We cannot assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures in 2015 could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include traditional reserve base borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We cannot assure you that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

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

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. 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. If we are unable to replace our current production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected. 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. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

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. Further, the success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions.

No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

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

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

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

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition.

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

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. As of December 31, 2014, Grizzly had approximately 830,000 net acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. Our total net investment in Grizzly was approximately \$180.2 million as of December 31, 2014. Grizzly has three oil sands projects in various stages of development. Grizzly commenced commercial production from its Algar Lake Phase 1 steam-assisted gravity drainage, or SAGD, oil sand project during the second quarter of 2014 and has received regulatory approval for up to 11,300 barrels per day of bitumen production. Grizzly produced approximately 1,400 barrels of bitumen per day at its Algar Lake SAGD project during the fourth quarter of 2014. Grizzly has announced that it expects bitumen production to reach its 6,000 barrels per day peak production rate by the fourth quarter of 2015. In the first quarter of 2012, Grizzly acquired the May River property comprising approximately 47,000 acres. An initial 12,000 barrel per day development application was filed with the regulatory authorities in the fourth quarter of 2013, covering the eastern portion of the May River lease. The development application continues to move through the regulatory process and is expected to be approved by mid-2015. In the first quarter of 2014, a 2-D seismic program covering approximately 83 kilometers was completed to more fully define the resource over the remaining lease beyond the development application area. At the Thickwood thermal project, a development application for a 12,000 barrel per day oil sands project was filed in the fourth quarter of 2012. Since then, the Alberta Energy Regulator, or AER, announced it is implementing a policy for future regulatory requirements for reservoir containment in shallow SAGD areas, which impacts the Thickwood application. Additional work to advance the Thickwood application will be required and is expected to be addressed once the May River development approval is received. Grizzly has also developed delineation drilling, seismic and regulatory work plans at its Cadotte, Peace River property. Grizzly is pursuing a rail marketing strategy to ensure consistent and flexible access to premium markets for its production, including its Windell truck to rail terminal located near Conklin, Alberta, which commenced transloading blended bitumen production from Algar Lake on to rail cars for delivery to the US Gulf Coast markets in the second quarter of 2014. 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, or that if one or more of these projects are completed that they will be successful or that we realize a return on our investment.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services 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 Michael G. Moore, our Chief Executive Officer and President, Aaron Gydosik, our Chief Financial Officer, and our geophysicists or our lead operations personnel, 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.

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) Ryder Scott with respect to our Utica Shale acreage at December 31, 2014, 2013 and 2012, (ii) Netherland, Sewell & Associates, Inc., or NSAI, with respect to our WCBB, Hackberry and Niobrara fields at each of December 31, 2014, 2013 and 2012 and (iii) our personnel with respect to our overriding royalty and non-operated interests at December 31, 2014, 2013 and 2012. 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 2014, 2013 and 2012 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, 2014, 2013 and 2012, 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 2014, 2013 and 2012 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, 2014, 2013 and 2012, 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.

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

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit

our ability to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe.

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

Approximately 51.4% of our total estimated proved reserves at December 31, 2014, were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

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.

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 and from our Utica Shale acreage. In October 2006, for example, a natural gas line in our WCBB 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. With respect to our Utica Shale acreage where we are focusing a significant portion of our exploration and development activity, historically there has been no or only limited infrastructure in this area and the commencement of production from our initial and subsequent wells on our Utica Shale acreage has been delayed due to challenges in obtaining rights-of-way and acquiring necessary state and federal permitting and the completion of facilities by our midstream service provider. If we are unable, for any sustained period, to have access to 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.

Substantially all of our producing properties are located in Eastern Ohio and Louisiana, making us vulnerable to risks associated with operating in these regions.

Our largest fields by production are located in Eastern Ohio and 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 in these geographic regions caused by weather conditions such as snow, ice, fog, 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 and it is possible that certain types of coverage may not 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 1,000 drilling locations on our Louisiana, Ohio and Western Colorado properties assuming full development of all of our acreage. 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 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. We may face liability for environmental damage caused by previous owners of properties purchased by us, which liabilities may or may not be covered by insurance. 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. 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. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

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

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

Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

We have entered into a compliance agreement with the Ohio Division of Oil and Gas Resources Management and, if we fail to comply with the conditions of the compliance agreement, all or part of our drilling and producing operations in the State of Ohio may be suspended.

In September 2013, we entered into a compliance agreement with the Ohio Division of Oil and Gas Resources Management, or the Division, concerning aspects of our operations at seven drilling sites in Ohio. We had previously notified the Division of brine contamination at these drilling sites. After receipt of this notification, the Division conducted an investigation and determined that certain contaminants were escaping from underneath the containment liners at these locations. In the compliance agreement, we agreed, among other things, to conduct our production operations in compliance with all requirements of applicable regulations, implement a remediation plan and make a payment of \$250,000. We are continuing to work with the Division to fulfill our obligations under the compliance agreement and to enhance our materials handling protocols. If the Chief of the Division determines that we have failed to comply with the conditions set forth in the compliance agreement, the Chief may suspend all or part of our drilling and production operations in the State of Ohio for a period determined by the Chief, and we could incur additional penalties and costs.

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. In addition, to the extent we engage in horizontal drilling, those activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. Furthermore, certain of the new techniques we are adopting, such as infill drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of infill drilling, offset wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing. The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently we are less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, and/or declines in natural gas and oil prices, the return on our investment in these areas may not be as

attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

We have been an early entrant into the Utica Shale in Eastern Ohio. As a result, our drilling results in this area may vary, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of December 31, 2014, had spud 151 wells, 101 of which were completed and are producing. In 2014, we spud 85 gross (67.2 net) wells, of which 36 were completed as producing wells, two were non-productive and, as of December 31, 2014, 41 were in various stages of completion and six were still being drilled. As of February 13, 2015, we had spud five gross (four net) wells during 2015. As of February 13, 2015, three of these wells were in various stages of completion and two were still being drilled. In addition, 110 gross (13.3 net) wells were drilled by other operators on our Utica Shale acreage during 2014. We currently intend to drill 46 to 52 gross (28 to 32 net) wells on our Utica Shale acreage in 2015 and anticipate an additional 11 to 16 gross (four to six net) wells will be drilled by other operators on our Utica Shale acreage in 2015. While our costs to acquire undeveloped acreage in this emerging play have generally been less than those of later entrants into a developing play, our drilling results in this area are more uncertain than drilling results in areas that are developed and producing. Since the Utica Shale has limited production history and since we have limited experience drilling in this play, it is difficult to predict our future drilling results. Our cost of drilling, completing and operating wells in this area may be higher than initially expected, and the value of our undeveloped acreage in the Utica Shale may decline if drilling results are unsuccessful. We cannot assure you that unproved property acquired, or undeveloped acreage leased, by us in the Utica Shale or other emerging plays will be profitably developed, that 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.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of 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, the following:

- effectively controlling the level of pressure flowing from particular wells;
- landing our wellbore 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 wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore 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 more limited in assessing future drilling results in these areas. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated 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;
- 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.

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

A significant portion of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Our 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. While none of our Utica Shale acreage leases are scheduled to expire until 2015, at that time 25% of our total Utica Shale undeveloped acreage as of December 31, 2014 will be subject to expiration, with 29% of such acreage expiring in 2016, 5% in 2017, 13% in 2018 and 10% thereafter, although our Utica Shale leases generally grant us the right to extend these leases for an additional five-year period. As of December 31, 2014, leases representing 14%, 31%, 6%, 7% and 24%, respectively, of our total Niobrara Formation undeveloped acreage are scheduled to expire in 2015, 2016, 2017, 2018 and thereafter. The cost to renew expiring 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.

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

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

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 and could expose us to significant liabilities.

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

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

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and natural gas commissions. The Environmental Protection Agency, or EPA, however, has in the past 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. In addition, on May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. Moreover, the EPA announced on October 20, 2011 that it is launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards in early 2015 that such wastewater must meet before being transported to a treatment plant. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting “flowback,” as well as “produced water.” If adopted, the new pretreatment rules will require operators to pretreat wastewater before transferring it to a treatment facility that discharges to surface water. 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.

In August 2012, the EPA published final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes NSP standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities.

The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules will require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that are likely responsive to some of these requests. For example, on September 23, 2013, the EPA published an amendment extending compliance dates for certain storage vessels. Also, on December 19, 2014, the EPA released final updates and clarifications to the NSP standards. In addition, on January 14, 2015, the EPA announced a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. In addition, the U.S. Department of the Interior, or DOI, published a revised proposed rule on May 24, 2013, that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. The DOI announced its intent to finalize the rule in 2014, however, the final rule remains pending.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. 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 EPA is currently evaluating the potential impacts of hydraulic fracturing on drinking water resources, with results of the study anticipated to be available March 2015. The White House Council on Environmental Quality is conducting an administration-wide review of hydraulic fracturing practices. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shale formations by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

Several states and local jurisdictions 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, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. For a more detailed discussion of state and local laws and initiatives concerning hydraulic fracturing, see “*Business-Regulation-Regulation of Hydraulic Fracturing*” above. Also, on May 6, 2013, the DOI issued a revised proposed 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 extensively in connection with the development and production of certain of our oil and natural gas properties and any increased federal, state, local, foreign or international regulation of hydraulic fracturing or offshore drilling, including legislation and regulation in the states in which we operate, could reduce the volumes of oil and natural gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations are adopted that significantly restrict hydraulic fracturing, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local 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, state or local laws governing hydraulic fracturing.

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), or Dodd-Frank Act, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation was signed into law by the President on July 21, 2010. In its rulemaking under the legislation, the Commodities Futures Trading Commission, or CFTC, has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions). The CFTC's final rule was set aside by the U.S. District Court for the District of Columbia on September 28, 2012 and remanded to the CFTC to resolve ambiguity as to whether statutory requirements for such limits to be determined necessary and appropriate were satisfied. As a result, the rule has not yet taken effect, although the CFTC has indicated that it intends to appeal the court's decision and that it believes the Dodd-Frank Act requires it to impose position limits. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions.

In addition, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirement to use cleared exchanges, rather than hedging over-the-counter, and the requirements to post margin in connection with hedging activities. While it is not possible at this time to predict when the CFTC will finalize certain other related rules and regulations, the Dodd-Frank Act and related regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, our hedging would become more expensive and we may decide to alter our hedging strategy.

The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our derivative contracts in existence at that time, and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

From time to time, legislative proposals are made that would, if enacted, make significant changes to U.S. tax laws. These proposed changes have included, but are not limited to, (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, (iii) the repeal of the percentage depletion allowance for oil and natural gas properties; (iv) an extension of the amortization period for certain geological and geophysical expenditures and (v) implementing certain international tax reforms.

These proposed changes in the U.S. tax law, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to natural gas and oil exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

In February 2013, the Governor of the State of Ohio proposed a plan in the Ohio House to enact new severance taxes on the oil and gas industry. The proposal was part of the state budget bill. Due to pressure from the State Senate, the proposal was removed from the bill. The bill then passed without the severance tax on June 7, 2013, with an effective date of July 1, 2013. Later in 2013, the Ohio House introduced a stand-alone bill to address the severance tax. HB 375 was introduced on December 4, 2013 and after many hearings and amendments, contained a 2.5% severance tax on horizontal drillers with a percentage of the proceeds earmarked for affected communities in Southeastern Ohio. This bill passed the Ohio House on May 14, 2014 and was pending in the Ohio Senate. The Ohio State Senate held a hearing on the bill, but there was no further movement before the summer recess of the Ohio Legislature.

In February 2015, the Governor of Ohio proposed another plan to enact new severance taxes on the oil and gas industry as part of the state budget proposal to finance a reduction in personal income taxes and other initiatives. The proposal would impose a 6.5% tax on oil and gas sold at the wellhead.

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

In December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective in January 2011 and purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule, also known as the "tailoring rule," in May 2010, and it also became effective in January 2011. The tailoring rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the Clean Air Act. On June 23, 2014, in *UARG v. EPA* the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD and Title V programs. On December 19, 2014, the EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court's decision in *UARG v. EPA*. In its preliminary guidance, the EPA indicates it will undertake a rulemaking action no later than December 31, 2015 to rescind any PSD permits issued under the portions of the Tailoring Rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. 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 addition, in August 2012, the EPA established NSP standards for volatile organic compounds and sulfur dioxide and an air toxic standard for oil and natural gas production, transmission, and storage. The rules include the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several other sources, such as storage tanks and other equipment, and limits methane emissions from these sources in an effort to reduce GHG emissions.

The EPA has continued to adopt GHG regulations of other industries, such as the September 2013 and June 2014 proposed GHG rules that, if finalized, would set NSP standards for new and existing coal-fired and natural gas-fired power plants, respectively, which could have an adverse effect on our financial condition, results of operation and cash available for distribution to the extent we acquire working interests in the future. The EPA is also considering additional regulation of greenhouse gases as “air pollutants.” As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility. In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The U.S. Congress has not adopted such legislation at this time, but it may do so in the future, and many states continue to pursue regulations to reduce greenhouse gas emissions. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry, and 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 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 differential less transportation charges. Shell is the purchaser of our Utica Shale oil and pays us WTI less a differential. MarkWest Utica currently markets our Utica Shale NGLs and remits to us a weighted average selling price less a marketing fee. We have NAESBs in place with various purchasers for our Utica Shale natural gas production. In 2014, our Utica Shale natural gas and natural gas liquids were sold under monthly, seasonal and long term contracts and, as needed, through daily trades. The majority of purchases are transacted at the tailgate of the plants with available pricing based on Platts Gas Daily - Appalachian - Dominion South Point (Dominion Eastern and Dominion Transmission) or Texas Eastern M2 Zone when sold in the Utica Basin. To maintain flow assurance and price stability, and as discussed under "- Transportation and Takeaway Capacity," we have entered into agreements to transport a portion of our natural gas production out of the Utica Basin. These agreements have pricing based on the appropriate delivery point less transportation charges and fuel. During the year ended December 31, 2014, we sold approximately 99% of our oil production to Shell, 100% of our natural gas liquids production to MarkWest Utica, and 40%, 32% and 19% of our natural gas production to BP, DTE Energy Trading, Inc. and Hess, respectively. During the year ended December 31, 2013, we sold approximately 99% of our oil production to Shell, 100% of our natural gas liquids production to MarkWest Utica and 32%, 31% and 17% of our natural gas production to Sequent Energy Management, L.P., Hess and Interstate Gas Supply, Inc., respectively. During 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.

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 natural gas to barrels at the ratio of six Mcf of natural 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 2014, 2013 and 2012 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 are exposed to fluctuations in the price of natural gas and oil. Although we have hedged a portion of our estimated 2015 production, we may still be adversely affected by continuing and prolonged declines in the price of natural gas and oil.

We use fixed price swaps to reduce price volatility associated with certain of our oil and natural gas sales, but these hedges may be inadequate to protect us from continuing and prolonged declines in the price of oil and natural gas. For the period from January 2015 through March 2015, we entered into fixed price swaps for 190,625 MMBtu per day at a weighted average price of \$4.12. For April 2015, we entered into fixed price swaps for 191,250 MMBtu per day at a weighted average price of \$4.05. For the period from May 2015 through June 2015, we entered into fixed price swaps for 201,250 MMBtu per day at a weighted average price of \$4.05. For the period from July 2015 through August 2015, we entered into fixed price swaps for 216,875 MMBtu per day at a weighted average price of \$4.04. For September 2015, we entered into fixed price swaps for 246,875 MMBtu per day at a weighted average price of \$3.97. For the period from October 2015 through December 2015, we entered into fixed price swaps for 262,500 MMBtu per day at a weighted average price of \$3.96. For the period from January 2016 through March 2016, we entered into fixed price swaps for 252,500 MMBtu per day at a weighted average price of \$3.82. For April of 2016 we entered into fixed price swaps for 242,500 MMBtu per day at a weighted average price of \$3.81. For the period from May 2016 through December 2016, we entered into fixed price swaps for 172,500 MMBtu per day at a weighted average price of \$3.73. For the period from January 2017 through June 2017, we entered into fixed price swaps for 142,500 MMBtu per day at a weighted average price of \$3.67. For the period from July 2017 through December 2017, we entered into fixed price swaps for 80,000 MMBtu per day at a weighted average price of \$3.45. For the period from January 2018 through December 2018, we entered into fixed price swaps for 30,000 MMBtu per day at a weighted average price of \$3.40. For the period from March 2015 through June 2016, we entered into fixed price swaps for 1,000 barrels of oil per day at a weighted average price of \$62.25. For the period from March 2015 through December 2016, we entered into natural gas basis swap positions, which settle on the pricing index to basis differential of MichCon to the NYMEX Henry Hub natural gas price for 30,000 MMBtu per day at a hedge differential of \$.02 and for 10,000 MMBtu per day at a hedge differential of \$.01. Under the 2015 contracts, we have hedged approximately 47% to 52% of our estimated 2015 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil and natural gas prices increase. Further, to the extent that the price of oil and natural gas remains at current levels or declines further, we will not be able to hedge future production at the same level as our current hedges, and our results of operations and financial condition would be negatively impacted.

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, 2014, we had total indebtedness (net of associated accrued discount and premium) of approximately \$716.5 million, including \$614.7 million attributable to our senior notes. We had borrowing base availability of \$306.4 million under our secured revolving credit facility after giving effect to an aggregate of \$43.6 million of letters of credit and outstanding borrowings of \$100.0 million.

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

- 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.

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, including the senior notes, depends on our future performance, which is subject to economic, financial, competitive and other factors

beyond our control. Our business may not 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. However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. 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 revolving credit facility and the indenture governing the senior notes 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.

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

Our secured revolving credit facility and the indenture governing the senior notes 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.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants contained in our revolving credit facility and the indenture governing the senior notes. In addition, our revolving credit facility requires us to maintain certain financial ratios and tests. The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

A breach of any of these restrictive covenants could result in default under our revolving credit facility. If default occurs, the lenders under our 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 indenture governing the senior notes. 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 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 revolving credit facility and the senior notes were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full that indebtedness.

Any significant reduction in our borrowing base under our revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our revolving credit facility if required as a result of a borrowing base redetermination.

Availability under our revolving credit facility is currently subject to a borrowing base of \$450.0 million. The borrowing base is subject to scheduled semiannual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors. As of December 31, 2014, we had \$100.0 million of borrowings under our revolving credit facility. We intend to continue borrowing under our revolving credit facility in the future. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow. Further if, the outstanding borrowings under our revolving credit facility were to exceed the borrowing base as a result of any such redetermination, we would be required to repay the excess. 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.

We may still be able to incur substantial additional indebtedness in the future, which 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. The terms of our revolving credit facility and the indenture governing the senior notes restrict, but in each case do not completely prohibit, us from doing so. As of December 31, 2014, our borrowing base under our revolving credit facility was set at \$450.0 million and we had \$100.0 million of borrowings outstanding under this facility. In addition, the indenture governing the senior notes allows us to issue additional notes under certain circumstances which will also be guaranteed by the guarantors. The indenture governing the senior notes also allows us to incur certain other additional secured debt and allows us to have subsidiaries that do not guarantee the senior notes and which may incur additional debt, which would be structurally senior to the senior notes. In addition, the indenture governing the senior notes does not prevent us from incurring other liabilities that do not constitute indebtedness. If we or a guarantor incur any additional indebtedness that ranks equally with the senior notes (or with the guarantees thereof), including additional unsecured indebtedness or trade payables, the holders of that indebtedness will be entitled to share ratably with holders of the senior notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us or a guarantor. 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.

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

Our earnings are exposed to interest rate risk associated with borrowings under our revolving credit facility. 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. At December 31, 2014, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 1.91%. A 1% increase in interest rates would increase interest expense by approximately \$1.0 million per year, based on \$100.0 million outstanding under our revolving credit facility as of December 31, 2014. As of December 31, 2014, we did not hedge our interest rate risk. An increase in our interest rate at the time we have variable interest rate borrowings outstanding under our revolving credit facility will increase our costs, which may have a material adverse effect on our results of operations and financial condition.

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, 2014, we had a net operating loss, or NOL, carry forward of approximately \$3.1 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, 2015, there were 85,684,604 shares of our common stock issued and outstanding, excluding 358,079 shares of unvested restricted stock awarded under our Amended and Restated 2005 Stock Incentive Plan and 5,000 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.

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.
- The ability to book proved undeveloped reserves, subject to certain exceptions, only if they relate to wells scheduled to be drilled within five years of the date of booking, as well as the requirement to write down proved undeveloped reserves if the associated wells are not drilled within the required five-year time-frame.
- 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, 2014 were prepared by Ryder Scott with respect to our assets in the Utica Shale in Eastern Ohio (97% of our proved reserves at December 31, 2014), by NSAI with respect to our WCBB, Hackberry and Niobrara fields (3% of our proved reserves at December 31, 2014) and by our personnel with respect to our overriding royalty and non-operated interests (less than 1% of our proved reserves at December 31, 2014).

Ryder Scott and NSAI 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 Ryder Scott and NSAI, our independent reserve engineers, to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Utica Shale and our WCBB, Hackberry and Niobrara fields. Our internal technical team members meet with Ryder Scott and NSAI periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to Ryder Scott and NSAI for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs and other considerations, including availability and costs of infrastructure and status of permits. Our proved reserves attributable to our other minority interests are prepared internally by our internal staff of petroleum engineers and geoscience professionals. Our

Vice President of Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. He is a petroleum engineer with over 35 years of reservoir and operations experience and our geophysical staff has 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;
- verification of property ownership by our land department;
- preparation of reserve estimates by our experienced reservoir engineers or under their direct supervision;
- direct reporting responsibilities by our reservoir engineering department to our Chief Executive Officer;
- 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;
- provision of quarterly updates to our board of directors regarding operational data, including production, drilling and completion activity levels and any significant changes in our reserves;
- annual review by our board of directors of our year-end reserve report and year-over-year changes in our proved reserves, as well as any changes to our previously adopted development plans;
- annual review and approval by our senior management and our board of directors of a multi-year development plan; and
- annual review by our senior management of adjustments to our previously adopted development plan and considerations involved in making such adjustments.

Further, during 2014, we implemented additional procedures in connection with our year-end reserve preparation and annual capital budget determination, including:

- review by our board of directors of changes in our previously approved development plan made by senior management and technical staff during the year, including the substitution, removal or deferral of PUD locations.

The following table sets forth our estimated proved reserves at December 31, 2014, 2013 and 2012:

	Year Ended December 31,								
	2014			2013			2012		
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)
Proved developed	5,719	345,166	12,379	5,609	94,552	3,527	5,175	18,482	44
Proved undeveloped	3,778	373,840	13,889	2,737	51,894	2,148	2,931	15,289	101
Total (1)	9,497	719,006	26,268	8,346	146,446	5,675	8,106	33,771	145

	Year Ended December 31,		
	2014	2013	2012
Total net proved oil and natural gas reserves (MMcfe) (1)	933,598	230,574	83,274
PV-10 value (in millions) (2)	\$ 1,840.8	\$ 696.9	\$ 436.8
Standardized measure (in millions) (3)	\$ 1,427.2	\$ 578.5	\$ 348.6

- (1) Estimates of reserves as of year-end 2014, 2013 and 2012 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, 2014, 2013 and 2012, respectively, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2014, 2013 and 2012. 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, 2014, 2013 and 2012 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 \$94.99 per barrel and \$4.35 per MMBtu for 2014, \$96.78 per barrel and \$3.67 per MMBtu for 2013 and \$91.32 per barrel and \$2.76 per MMBtu for 2012, 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:

	December 31,		
	2014	2013	2012
	(In thousands)		
Standardized measure of discounted future net cash flows	\$ 1,427,167	\$ 578,466	\$ 348,641
Add: Present value of future income tax discounted at 10%	413,671	118,445	88,206
PV-10 value	<u>\$ 1,840,838</u>	<u>\$ 696,911</u>	<u>\$ 436,847</u>

- (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, 2014, 2013 and 2012 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 19 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, 2014, our proved undeveloped reserves totaled 3,778 MBbls of oil, 373,840 MMcf of natural gas and 13,889 MBbls of NGLs, for a total of 479,844 MMcfe. Approximately 99% of our PUDs at year-end 2014 were located in our Utica field. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

We record PUD reserves only after a development plan has been approved by our senior management and board of directors to complete the associated development drilling within five years from the time of initial booking. The PUD locations identified in our development plan are determined based on an analysis of the information that we have available at that time. After a development plan has been adopted, we may periodically make adjustments to the approved development plan due to events and circumstances that have occurred subsequent to the time the plan was approved. These circumstances may include delays in the availability of infrastructure, well permitting delays, changes in commodity price outlook and costs, and new data from recently completed wells. During 2014, we did not make any material adjustments to our development plan with respect to our PUD locations booked in our reserve report for the year ended December 31, 2013 and scheduled to be drilled during 2014. Changes in PUDs that occurred during 2014 were primarily due to:

- Additions of 448.1 Bcfe attributable to 2014 extensions in our Utica field;
- Conversion of approximately 37.8 Bcfe attributable to PUDs into proved developed reserves;
- Acquisition of approximately 4 Bcfe from our Rhino acquisition; and
- Downward revisions of 15.8 Bcfe due to the exclusion of PUD locations in our Southern Louisiana and Utica fields that were not expected to be drilled within five years of initial booking.

Costs incurred relating to the development of PUDs were approximately \$68.2 million in 2014. Estimated future development costs relating to the development of PUDs are projected to be approximately \$221.0 million in 2015, \$93.1 million in 2016, \$215.4 million in 2017, \$73.2 million in 2018 and \$59.3 million in 2019.

All PUD drilling locations included in our 2014 reserve report are scheduled to be drilled within five years of initial booking.

As of December 31, 2014, 2% 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:

	2014	2013	2012
Production Volumes:			
Oil (MBbls)	2,684	2,317	2,323
Gas (MMcf)	59,318	8,891	1,108
Natural gas liquids (MGal)	86,092	13,416	2,714
Gas equivalents (MMcfe)	87,719	24,709	15,436
Average Prices:			
Oil (per Bbl)	\$ 92.18 ⁽¹⁾	\$ 96.74 ⁽¹⁾	\$ 104.46 ⁽¹⁾
Gas (per Mcf)	\$ 5.55 ⁽¹⁾	\$ 2.36 ⁽¹⁾	\$ 2.91
Natural gas liquids (per Gal)	\$ 1.09	\$ 1.27	\$ 0.98
Gas equivalents (per Mcfe)	\$ 7.65	\$ 10.61	\$ 16.11
Production Costs:			
Average production costs (per Mcfe)	\$ 0.59	\$ 1.08	\$ 1.57
Average production taxes and midstream costs (per Mcfe)	\$ 1.01	\$ 1.54	\$ 1.90
Total production and midstream costs and production taxes (per Mcfe)	<u>\$ 1.60</u>	<u>\$ 2.62</u>	<u>\$ 3.47</u>

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

	Per barrel
January – December 2014	\$ 102.79
January – December 2013	\$ 100.90
January – December 2012	\$ 108.31
	Per MMBtu
January – December 2014	\$ 4.06
January – December 2013	\$ 4.00

Excluding the effect of fixed price swaps, the average price for 2014 would have been \$89.88 per barrel of oil, \$3.81 per Mcf of gas and \$6.40 per Mcfe. The total volume hedged for 2014 represented approximately 62% of our total sales volumes for the year. Excluding the effect of fixed price swaps, the average price for 2013 would have been \$104.51 per barrel of oil, \$3.73 per Mcf of gas and \$11.83 per Mcfe. The total volume hedged for 2013 represented approximately 48% of our total sales volumes for the year. Excluding the effect of fixed price swap contracts, the average oil price for 2012 would have been \$106.11 per barrel of oil and \$16.35 per Mcfe. The total volume hedged for 2012 represented approximately 46% 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, 2014:

	Year Ended December 31,		
	2014	2013	2012
Utica Shale			
Net Production			
Oil (MBbls)	883	315	25
Gas (MMcf)	58,919	8,439	365
NGL (Mgal)	86,051	13,384	80
Total (MMcfe)	76,512	12,238	525
Average Sales Price:			
Oil (per Bbl)	\$ 78.63	\$ 83.67	\$ 78.21
Gas (per Mcf)	\$ 5.56	\$ 2.29	\$ 2.99
NGL (per Gal)	\$ 1.09	\$ 1.27	\$ 1.56
Average Production Cost (per Mcfe)	\$ 0.38	\$ 0.59	\$ 1.38

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, 2014.

Field	NRI/WI (1) Percentages	Productive Oil Wells (2)		Productive Gas Wells		Non-Productive Oil Wells		Non-Productive Gas Wells		Developed Acreage (3)		Undeveloped Acreage	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Utica Shale (4)	34.52/41.46	171	63.29	24	17.56	3	2.66	—	—	21,652	19,340	163,330	161,051
West Cote Blanche Bay Field (5)	80.108/100	123	123	—	—	168	168	17	17	5,668	5,668	—	—
E. Hackberry Field (6)	80.945/100	39	39	—	—	107	107	—	—	3,931	3,931	581	581
W. Hackberry Field	79.167/100	6	6	—	—	7	7	—	—	1,192	1,192	—	—
Niobrara Formation (7)	39.83/47.85	6	3	—	—	—	—	—	—	3,502	1,751	8,464	4,149
Bakken Formation (8)	1.51/1.83	18	0.3	—	—	—	—	—	—	1,862	163	3,505	701
Overrides/Royalty Non-operated	Various	384	0.42	—	—	—	—	—	—	—	—	—	—
Total		747	235.01	24	17.56	285	284.66	17	17	37,807	32,045	175,880	166,482

- (1) Net Revenue Interest (NRI)/Working Interest (WI).
- (2) Includes one gross and net well at WCBB that is producing intermittently.
- (3) Developed acres are acres spaced or assigned to productive wells. Approximately 16% of our acreage is developed acreage and has been perpetuated by production.
- (4) In 2015, 25% of our total Utica Shale undeveloped acreage as of December 31, 2014 will be subject to expiration, with 29% of such acreage expiring in 2016, 5% in 2017, 13% in 2018 and 10% thereafter. Our Utica Shale leases generally grant us the right to extend these leases for an additional five-year period. NRI/WI is from wells that have been drilled or in which we have elected to participate. Includes 91 gross (6.96 net) oil wells and 3 gross (.61 net) gas wells drilled by other operators on our acreage.

- (5) 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).
- (6) NRI shown is for producing wells.
- (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 14%, 31%, 6%, 7% and 24% of our total Niobrara undeveloped acreage are currently scheduled to expire in 2015, 2016, 2017, 2018 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 operated 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.

	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	161	161	150	150	92	92
Dry	—	—	—	—	1	0.5
Total	161	161	150	150	93	92.5
Development:						
Productive	119	100	80	63.8	70	57
Dry	7	6.8	2	2	8	7
Total	126	106.8	82	65.8	78	64
Exploratory:						
Productive	—	—	3	2.7	19	6
Dry	—	—	—	—	—	—
Total	—	—	3	2.7	19	6

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

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Price Range of Common Stock

Our common stock is 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
2013		
First Quarter	\$ 47.19	\$ 35.24
Second Quarter	54.07	43.98
Third Quarter	64.73	46.85
Fourth Quarter	69.81	53.93
2014		
First Quarter	\$ 71.35	\$ 52.28
Second Quarter	75.75	58.90
Third Quarter	65.18	51.59
Fourth Quarter	56.72	36.56
2015		
First Quarter (through February 25, 2015)	\$ 45.54	\$ 35.00

On February 25, 2015, the last reported sale price of our common stock on the NASDAQ Global Select Market was \$44.09.

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 23, 2015, there were 312 stockholders of record holding 85,684,604 shares of our outstanding common stock. There were approximately 28,487 beneficial owners of our common stock as of February 23, 2015.

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, 2014, December 31, 2013 and December 31, 2012 and the selected consolidated balance sheet data at December 31, 2014 and December 31, 2013 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, 2011 and December 31, 2010 and the selected consolidated balance sheet data at December 31, 2012, December 31, 2011 and December 31, 2010 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,				
	2014	2013	2012	2011	2010
	(In thousands, except share data)				
Selected Consolidated Statements of Operations Data:					
Revenues	\$ 671,266	\$ 262,753	\$ 248,926	\$ 229,254	\$ 127,921
Costs and expenses:					
Lease operating expenses	52,191	26,703	24,308	20,897	17,614
Production taxes	24,006	26,933	28,957	26,054	13,823
Midstream gathering and processing	64,467	11,030	443	279	143
Depreciation, depletion and amortization	265,431	118,880	90,749	62,320	38,907
General and administrative	38,290	22,519	13,808	8,074	6,063
Accretion expense	761	717	698	666	617
Loss (gain) on sale of assets	(11)	508	(7,300)	—	—
	<u>445,135</u>	<u>207,290</u>	<u>151,663</u>	<u>118,290</u>	<u>77,167</u>
Income from Operations	226,131	55,463	97,263	110,964	50,754
Other (Income) Expense:					
Interest expense	23,986	17,490	7,458	1,400	2,761
Interest income	(195)	(297)	(72)	(186)	(387)
Litigation settlement	25,500	—	—	—	—
Gain on contribution of investments	(84,470)	—	—	—	—
(Income) loss from equity method investments	(139,434)	(213,058)	(8,322)	1,418	977
	<u>(174,613)</u>	<u>(195,865)</u>	<u>(936)</u>	<u>2,632</u>	<u>3,351</u>
Income from Continuing Operations before Income Taxes	400,744	251,328	98,199	108,332	47,403
Income Tax Expense (Benefit)	153,341	98,136	26,363	(90)	40
Income from Continuing Operations	<u>247,403</u>	<u>153,192</u>	<u>71,836</u>	<u>108,422</u>	<u>47,363</u>
Discontinued Operations:					
Loss on disposal of Belize properties, net of tax	—	—	3,465	—	—
Net Income Available to Common Stockholders	<u>\$ 247,403</u>	<u>\$ 153,192</u>	<u>\$ 68,371</u>	<u>\$ 108,422</u>	<u>\$ 47,363</u>
Net Income Per Common Share—Basic:	<u>\$ 2.90</u>	<u>\$ 1.98</u>	<u>\$ 1.22</u>	<u>\$ 2.22</u>	<u>\$ 1.08</u>
Net Income Per Common Share—Diluted:	<u>\$ 2.88</u>	<u>\$ 1.97</u>	<u>\$ 1.21</u>	<u>\$ 2.20</u>	<u>\$ 1.07</u>

At December 31,

2014	2013	2012	2011	2010
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(In thousands)

Selected Consolidated Balance Sheet

Data:

Total assets	\$ 3,632,393	\$ 2,693,136	\$ 1,578,368	\$ 691,158	\$ 319,693
Total debt, including current maturity	\$ 716,484	\$ 299,187	\$ 299,038	\$ 2,283	\$ 51,917
Total liabilities	\$ 1,336,097	\$ 642,898	\$ 451,960	\$ 58,808	\$ 108,637
Stockholders' equity	\$ 2,296,296	\$ 2,050,238	\$ 1,126,408	\$ 632,350	\$ 125,051

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 focused on the exploration, exploitation, acquisition and production of natural gas, natural gas liquids and crude oil in the United States. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as development and exploratory drilling opportunities on high potential conventional and unconventional oil and natural gas prospects. Our principal properties are located in the Utica Shale primarily in Eastern Ohio and along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields. In addition, we have producing properties in the Niobrara Formation of Northwestern Colorado and the Bakken Formation. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, and interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. Until November 2014, we held an equity interest in Diamondback Energy, Inc., or Diamondback, a NASDAQ Global Select Market listed company to which we contributed our Permian Basin oil and natural gas interests in October 2012 immediately prior to Diamondback's initial public offering, or the Diamondback IPO. At December 31, 2014, we did not own any shares of Diamondback. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

In this Annual Report on Form 10-K, our oil and natural gas production is presented in cubic feet of natural gas equivalent, as compared to our production presentation in prior periods which was expressed in barrels of oil equivalent. This change in presentation is due to the change in our production mix from predominately oil and natural gas liquids to predominately natural gas and natural gas liquids that occurred during 2014. Certain changes have been made to prior year financial statements to conform to the current year's presentation.

2014 and 2015 Year to Date Highlights

- Oil and natural gas revenues increased 156% to \$670.8 million for the year ended December 31, 2014 from \$262.2 million for the year ended December 31, 2013.
- Production increased 255% to approximately 87,719 MMcfe for the year ended December 31, 2014 from approximately 24,709 MMcfe for the year ended December 31, 2013.
- During 2014, we spud 130 gross (112 net) wells, participated in an additional 112 gross (13 net) wells that were drilled by other operators on our Utica Shale and Bakken acreage and recompleted 161 gross and net wells. Of our 130 new wells spud during 2014, 73 were completed as producing wells, seven were non-productive, and, at year end, 44 were in various stages of completion and six were drilling.
- In 2014, we acquired approximately 8,200 net acres in the Utica Shale from Rhino for a total purchase price of \$182.0 million (\$179.5 million net of purchase price adjustments). We are the operator of substantially all of this acreage.
- As of February 13, 2015, we held leasehold interests in approximately 188,000 gross (184,000 net) acres in the Utica Shale. During 2014, we spud 85 gross (67.2 net) wells on our Utica Shale acreage and, during 2015 (through February 13, 2015), we had spud five gross (four net) wells. As of February 13, 2015, three of these wells were in various stages of completion and two were still being drilled.
- In June, September and November of 2014, we sold shares of our Diamondback common stock in underwritten public offerings for an aggregate of \$258.4 million in net proceeds. As of December 31, 2014, we did not own any shares of Diamondback common stock.

- In August of 2014, we issued \$300.0 million in aggregate principal amount of our 7.750% Senior Notes due 2020, resulting in net proceeds to us of approximately \$312.0 million, a portion of which we used to repay all outstanding borrowings under our senior secured revolving credit facility. We used the remaining net proceeds for general corporate purposes, which included funding a portion of our 2014 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 prior twelve months, 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 \$1.5 billion at December 31, 2014 and \$1.0 billion at December 31, 2013. 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 prior twelve months 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, 2014.

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 inflation of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjusted 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. Ryder Scott Company, L.P., Netherland, Sewell & Associates, Inc., and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2014 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 the guidelines of the Securities and Exchange Commission, or SEC. 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 December 31, 2014, a valuation allowance of \$3.1 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 natural 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% and/or investments in which we have significant influence 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 from equity method investments in the consolidated statements of operations. As of December 31, 2014, we had sold all of our shares of common stock of Diamondback.

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. At December 31, 2014, we fully impaired our investment in Tatex III. There was no impairment of equity method investments as of December 31, 2013.

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 and natural gas 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.

See "Item 7. Commodity Price Risk" for a summary of our fixed price swaps in place as of December 31, 2014.

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:

	2014	2013	2012
Production Volumes:			
Oil (MBbls)	2,684	2,317	2,323
Gas (MMcf)	59,318	8,891	1,108
Natural gas liquids (MGal)	86,092	13,416	2,714
Gas equivalents (MMcfe)	87,719	24,709	15,436
Average Prices:			
Oil (per Bbl)	\$ 92.18 ⁽¹⁾	\$ 96.74 ⁽¹⁾	\$ 104.46 ⁽¹⁾
Gas (per Mcf)	\$ 5.55 ⁽¹⁾	\$ 2.36 ⁽¹⁾	\$ 2.91
Natural gas liquids (per Gal)	\$ 1.09	\$ 1.27	\$ 0.98
Gas equivalents (per Mcfe)	\$ 7.65	\$ 10.61	\$ 16.11
Production Costs:			
Average production costs (per Mcfe)	\$ 0.59	\$ 1.08	\$ 1.57
Average production taxes and midstream costs (per Mcfe)	\$ 1.01	\$ 1.54	\$ 1.90
Total production and midstream costs and production taxes (per Mcfe)	\$ 1.60	\$ 2.62	\$ 3.47

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

	Per barrel
January – December 2014	\$ 102.79
January – December 2013	\$ 100.90
January – December 2012	\$ 108.31
	Per MMBtu
January – December 2014	\$ 4.06
January – December 2013	\$ 4.00

Excluding the net effect of fixed price swaps, the average price for 2014 would have been \$89.88 per barrel of oil, \$3.81 per Mcf of gas and \$6.40 per Mcfe. The total volume hedged for 2014 represented approximately 62% of our total sales volumes for the year. Excluding the effect of fixed price swaps, the average oil price for 2013 would have been \$104.51 per barrel of oil, \$3.73 per Mcf of gas and \$11.83 per Mcfe. The total volume hedged for 2013 represented approximately 48% of our total sales volumes for the year. Excluding the net effect of forward sales contracts, the average oil price for 2012 would have been \$106.11 per barrel of oil and \$16.35 per Mcfe. The total volume hedged for 2012 represented approximately 46% of our total sales volumes for the year.

From 2013 to 2014, our net equivalent gas production increased 255% from 24,709 MMcfe to 87,719 MMcfe primarily as a result of the development of our Utica Shale acreage. From 2012 to 2013, our net equivalent gas production also increased 60% from 15,436 MMcfe to 24,709 MMcfe due to the results of our 2013 drilling and recompletion activities. We currently estimate that our 2015 production will be between 157,680 and 175,200 MMcfe. However, our actual production may be different due to changes in our currently anticipated drilling and recompletion activities, changing economic climate, adverse weather conditions or other unforeseen events.

Comparison of the Years Ended December 31, 2014 and December 31, 2013

We reported net income of \$247.4 million for the year ended December 31, 2014 as compared to \$153.2 million for the year ended December 31, 2013. This 61% increase in period-to-period net income was due primarily to \$79.7 million of income recognized from our equity method investment in Diamondback, \$84.8 million of income recognized from our equity method investment in Blackhawk, \$84.5 million of income recognized from our contribution of investments to Mammoth and a 255% increase in net production to 87,719 MMcfe from 24,709 MMcfe, partially offset by a 28% decrease in realized Mcfe prices to \$7.65 from \$10.61, a \$25.5 million increase in lease operating expenses, a \$53.4 million increase in midstream gathering and processing expenses, a \$15.8 million increase in general and administrative expenses, a \$6.5 million increase in interest expense

and a \$55.2 million increase in income tax expense for the year ended December 31, 2014 as compared to the year ended December 31, 2013.

Oil and Gas Revenues. For the year ended December 31, 2014, we reported oil and natural gas revenues of \$670.8 million as compared to oil and natural gas revenues of \$262.2 million during 2013. This \$408.5 million, or 156%, increase in revenues was primarily attributable to a 255% increase in net production to 87,719 MMcfe from 24,709 MMcfe, partially offset by a 28% decrease in realized Mcfe prices to \$7.65 from \$10.61 due to a shift in our production mix toward natural gas and NGLs, for the year ended December 31, 2014 as compared to the year ended December 31, 2013.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2014 and December 31, 2013:

	Year Ended December 31,	
	2014	2013
Oil production volumes (MBbls)	2,684	2,317
Gas production volumes (MMcf)	59,318	8,891
Natural gas liquids production volumes (MGal)	86,092	13,416
Gas equivalents (MMcfe)	87,719	24,709
Average oil price (per Bbl)	\$ 92.18	\$ 96.74
Average gas price (per Mcf)	\$ 5.55	\$ 2.36
Average natural gas liquids (per Gal)	\$ 1.09	\$ 1.27
Gas equivalents (per Mcfe)	\$ 7.65	\$ 10.61

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to \$52.2 million for the year ended December 31, 2014 from \$26.7 million for the year ended December 31, 2013. This increase was mainly the result of an increase in expenses related to property taxes, compressor rentals, compressor repairs and maintenance, contract pumpers, environmental services, field supervision, location repair, rentals and salt water disposal.

Production Taxes. Production taxes decreased to \$24.0 million for the year ended December 31, 2014 from \$26.9 million for 2013. This decrease was primarily related to changes in our product mix and production location.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased by \$53.4 million to \$64.5 million for the year ended December 31, 2014 from \$11.0 million for 2013. This increase was primarily the result of midstream expenses related to our production volumes in the Utica Shale resulting from our 2014 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to \$265.4 million for the year ended December 31, 2014, and consisted of \$263.9 million in depletion of oil and natural gas properties and \$1.5 million in depreciation of other property and equipment, as compared to total DD&A expense of \$118.9 million for 2013. This increase was due to an increase in our full cost pool as a result of our capital activities as well as an increase in our production, partially offset by an increase 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 \$38.3 million for the year ended December 31, 2014 from \$22.5 million for the year ended December 31, 2013. This \$15.8 million increase was due to an increase in salaries, stock compensation expenses and benefits resulting from an increased number of employees, increases in legal expenses, corporate fees, consulting fees, rent expense associated with office space, bank service charges, computer support and franchise taxes, partially offset by an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense remained relatively flat at \$0.8 million for the years ended December 31, 2014 and 2013.

Interest Expense. Interest expense increased to \$24.0 million for the year ended December 31, 2014 from \$17.5 million for the year ended December 31, 2013 due primarily to our issuance of \$300.0 million of additional 7.75% Senior Notes due 2020 and increased borrowings under our revolving credit facility. On August 18, 2014, we issued \$300.0 million aggregate principal amount of our 7.75% Senior Notes due 2020, a portion of the net proceeds from which was used to repay all outstanding borrowings under our revolving credit facility. Total weighted debt outstanding under our revolving credit facility was \$22.8 million for the year ended December 31, 2014 as compared to no borrowings outstanding under such facility for 2013. Additionally, we capitalized approximately \$9.7 million and \$7.1 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2014 and December 31, 2013, respectively. This increase in capitalized interest in the 2014 period was the result of an increase in our undeveloped oil and natural gas properties.

Income Taxes. As of December 31, 2014, we had a net operating loss carry forward of approximately \$3.1 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, 2014, a valuation allowance of \$3.1 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 operations of \$153.3 million for the year ended December 31, 2014.

Comparison of the Years Ended December 31, 2013 and December 31, 2012

We reported net income of \$153.2 million for the year ended December 31, 2013 as compared to \$68.4 million for the year ended December 31, 2012. This 124% increase in period-to-period net income was due primarily to \$220.1 million of income recognized from our equity method investment in Diamondback and a 60% increase in net production to 24,709 MMcfe from 15,436 MMcfe, partially offset by a 34% decrease in realized Mcfe prices to \$10.61 from \$16.11, a \$2.4 million increase in lease operating expenses, a \$10.6 million increase in midstream gathering and processing expenses, an \$8.7 million increase in general and administrative expenses, a \$10.0 million increase in interest expense and a \$71.8 million increase in income tax expense for the year ended December 31, 2013 as compared to the year ended December 31, 2012.

Oil and Gas Revenues. For the year ended December 31, 2013, we reported oil and natural gas revenues of \$262.2 million as compared to oil and natural gas revenues of \$248.6 million during 2012. This \$13.6 million, or 5%, increase in revenues was primarily attributable to a 60% increase in net production to 24,709 MMcfe from 15,436 MMcfe, partially offset by a 34% decrease in realized Mcfe prices to \$10.61 from \$16.11, for the year ended December 31, 2013 as compared to the year ended December 31, 2012.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2013 and December 31, 2012:

	Year Ended December 31,	
	2013	2012
Oil production volumes (MBbls)	2,317	2,323
Gas production volumes (MMcf)	8,891	1,108
Natural gas liquids production volumes (MGal)	13,416	2,714
Gas equivalents (MMcfe)	24,709	15,436
Average oil price (per Bbl)	\$ 96.74	\$ 104.46
Average gas price (per Mcf)	\$ 2.36	\$ 2.91
Average natural gas liquids (per Gal)	\$ 1.27	\$ 0.98
Gas equivalents (per Mcfe)	\$ 10.61	\$ 16.11

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to \$26.7 million for the year ended December 31, 2013 from \$24.3 million for the year ended December 31, 2012. This increase was mainly the result of an increase in expenses related to property taxes, compressor rentals, compressor repairs and maintenance, contract pumpers, environmental services, insurance expense and salt water disposal.

Production Taxes. Production taxes decreased to \$26.9 million for the year ended December 31, 2013 from \$29.0 million for 2012. This decrease was primarily related to changes in our product mix and production location.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased by \$10.6 million to \$11.0 million for the year ended December 31, 2013 from \$0.4 million for 2012. This increase was primarily the result of midstream expenses related to our production volumes in the Utica Shale resulting from our 2013 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to \$118.9 million for the year ended December 31, 2013, and consisted of \$118.1 million in depletion of oil and natural gas properties and \$0.8 million in depreciation of other property and equipment, as compared to total DD&A expense of \$90.7 million for 2012. This increase was due to an increase in our full cost pool as a result of our capital activities as well as an increase in our production, partially offset by an increase 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 \$22.5 million for the year ended December 31, 2013 from \$13.8 million for the year ended December 31, 2012. This \$8.7 million increase was due to an increase in salaries, stock compensation expenses and benefits resulting from an increased number of employees, increases in legal expenses, corporate fees, consulting fees and fees for auditing services and a reduction in administrative services reimbursements under the acquisition team agreement, partially offset by an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense remained relatively flat at \$0.7 million for the years ended December 31, 2013 and 2012.

Interest Expense. Interest expense increased to \$17.5 million for the year ended December 31, 2013 from \$7.5 million for the year ended December 31, 2012 due largely to a full year of interest on our 7.75% Senior Notes due 2020. During 2013, we had no debt outstanding under our revolving credit facility as compared to total weighted average debt outstanding under our revolving credit facility of \$45.0 million in 2012, which 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. Additionally, we capitalized approximately \$7.1 million in interest expense to undeveloped oil and natural gas properties during the year ended December 31, 2013 as a result of increased interest costs incurred on our 7.75% Senior Notes. We did not capitalize any interest costs for the year ended December 31, 2012.

Income Taxes. As of December 31, 2013, we had a net operating loss carry forward of approximately \$4.2 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, 2013, a valuation allowance of \$4.7 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 operations of \$98.1 million for the year ended December 31, 2013.

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 facility and the issuances of equity and debt securities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and natural gas production. During 2014, we received net proceeds of \$312.0 million from the sale of our 7.750% Senior Notes due 2020. In addition, we received an aggregate of \$258.4 million in net proceeds from the sale of shares of our Diamondback common stock in 2014. We also received net proceeds of \$84.8 million from the sale of Blackhawk's equity interest in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC. In January 2013, we received \$32.8 million of net proceeds from the underwriters' exercise of their option to purchase the remaining shares of common stock subject to the over-allotment option granted in connection with our December 2012 equity offering. In 2013, we received an aggregate of \$733.8 million from the sale of shares of our common stock. In addition, we received an aggregate of \$192.7 million in net proceeds from the sale of shares of our Diamondback common stock in 2013.

Net cash flow provided by operating activities was \$409.9 million for the year ended December 31, 2014 as compared to net cash flow provided by operating activities of \$191.1 million for 2013. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 255% increase in our net Mcfe production, partially offset by a 28% decrease in net realized Mcfe prices.

Net cash flow provided by operating activities was \$191.1 million for the year ended December 31, 2013, as compared to net cash flow provided by operating activities of \$199.2 million for 2012. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 34% decrease in our net realized Mcfe prices, partially offset by a 60% increase in net Mcfe production.

Net cash used in investing activities for the year ended December 31, 2014 was \$1.1 billion as compared to \$664.3 million for 2013. During the year ended December 31, 2014, we spent \$1,329.3 million in additions to oil and natural gas properties, of which \$503.8 million was spent on our 2014 drilling and recompletion programs, \$317.8 million was spent on expenses attributable to the wells drilled and recompleted during 2013, \$7.8 million was spent on compressors and other facility enhancements, \$7.5 million was spent on plugging costs, \$257.8 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, and \$179.5 million was spent on the acquisition of producing properties and non-producing leasehold interests from Rhino, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, \$18.8 million was invested in Grizzly and \$45.2 million was invested in our other equity investments during the year ended December 31, 2014. We also received \$258.4 million from the sale of shares of Diamondback common stock during 2014. During the year ended December 31, 2014, we used cash from operations and proceeds from our 2013 equity and 2014 debt offerings for our investing activities.

Net cash used in investing activities for the year ended December 31, 2013 was \$664.3 million as compared to \$840.6 million for 2012. During the year ended December 31, 2013, we spent \$808.2 million in additions to oil and natural gas properties, of which \$335.2 million was spent on our 2013 drilling and recompletion programs, \$93.4 million was spent on expenses attributable to the wells drilled and recompleted during 2012, \$5.8 million was spent on compressors and other facility enhancements, \$2.0 million was spent on plugging costs, \$340.4 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, and \$5.2 million was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, \$33.9 million was invested in Grizzly and \$13.1 million was invested in our other equity investments during the year ended December 31, 2013. During the year ended December 31, 2013, we used cash from operations and proceeds from our 2012 and 2013 equity and debt offerings for our investing activities.

Net cash provided by financing activities for the year ended December 31, 2014 was \$410.2 million as compared to net cash provided by financing activities of \$765.1 million for 2013. The 2014 amount provided by financing activities is primarily attributable to the net proceeds of \$312.0 million from our 2014 debt offering and net borrowings under our revolving credit facility.

Net cash provided by financing activities for the year ended December 31, 2013 was \$765.1 million as compared to \$714.6 million for 2012. The 2013 amount provided by financing activities is primarily attributable to the net proceeds of \$765.1 million from our 2013 equity offerings.

Credit Facility. On September 30, 2010, we entered into a senior secured revolving credit facility with The Bank of Nova Scotia, as the lead arranger and administrative agent and certain lenders from time to time party thereto. On December 27, 2013, we amended and restated that credit agreement in its entirety. The amended and restated credit agreement provided for an increase in the maximum facility amount from \$350.0 million to \$1.5 billion, with an increase in borrowing base availability as of December 27, 2013 from \$50.0 million to \$150.0 million. The amended and restated credit agreement matures on June 6, 2018.

On April 23, 2014, we entered into a first amendment to the amended and restated credit agreement. The first amendment increased the letter of credit sublimit from \$20.0 million to \$70.0 million and provided for an increase in the borrowing base availability from \$150.0 million to \$275.0 million. The first amendment also made certain changes to the lenders and their respective lending commitments thereunder.

On November 26, 2014, we entered into a second amendment to the amended and restated credit agreement. The second amendment changed the definition of EBITDAX to exclude proceeds from the disposition of equity method investments and changed the ratio of funded debt to EBITDAX to be the ratio of net funded debt to EBITDAX. Net funded debt is funded debt less the amount of cash and short-term investments at the end of the relevant fiscal quarter. The second amendment requires the ratio of net funded debt to EBITDAX to be less than 3.50 to 1.00 for the period December 31, 2014 through June 30, 2015 and

then less than 3.25 to 1.00 for the periods thereafter. Further, the second amendment increased the letter of credit sublimit from \$70.0 million to \$125.0 million and provided for an increase in the borrowing base availability from \$275.0 million to \$450.0 million. The Bank of Nova Scotia, as sole lead arranger and administrative agent of our revolving credit facility, as part of the regular spring 2015 borrowing base redetermination process, informed us that it will be recommending to the lending syndicate an increase in our borrowing base under this facility from \$450.0 million to \$575.0 million. We expect final approval and implementation of the borrowing base increase to be completed within the next 30 to 45 days by the lending syndicate. As of December 31, 2014, \$100.0 million was outstanding under our revolving credit facility and total funds available for borrowing, after giving effect to an aggregate of \$43.6 million of letters of credit, were \$306.4 million. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guarantee our obligations under our revolving credit facility.

Advances under our revolving credit agreement 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 0.50% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (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 1.50% to 2.50%, plus (2) the London interbank offered rate that appears on pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or other service that displays an average London interbank offered rate as administered by ICE Benchmark Administration (or any other person that takes over the administration of such 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. At December 31, 2014, amounts borrowed under the revolving credit facility bore interest at the eurodollar rate (1.91%).

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 net funded debt to EBITDAX (net income, excluding (i) any non-cash revenue or expense associated with swap contracts resulting from ASC 815 and (ii) any cash or non-cash revenue or expense attributable to minority investment plus without duplication and, in the case of expenses, 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) exploration costs deducted in determining net income under successful efforts accounting, (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 (provided that expenses related to any unsuccessful dispositions will be limited to \$3.0 million in the aggregate) for a twelve-month period may not be greater than 3.50 to 1.00 for the period December 31, 2014 through June 30, 2015 and 3.25 to 1.00 for the twelve-month period ending September 30, 2015 and periods thereafter; 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, 2014.

Senior Notes. On October 17, 2012, we issued \$250.0 million in aggregate principal amount of our 7.75% 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 7.75% 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. We used a portion of the net proceeds from the offering of the October Notes to repay all amounts outstanding at such time under our revolving credit facility. We used the remaining net proceeds of the offering of the October Notes and the net proceeds of the offering of the December Notes for general corporate purposes, which includes funding a portion of our 2013 capital development plan. The October Notes and the December Notes were exchanged for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act in October 2013.

On August 18, 2014, we issued an additional \$300.0 million in aggregate principal amount of our 7.75% Senior Notes due 2020, or the August 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 August Notes were issued as additional securities under the existing senior note indenture. We used a portion of the net proceeds from the offering of the August Notes to repay all amounts outstanding at such time under our revolving credit facility. We used the remaining net proceeds from this offering for general corporate purposes, including funding a portion of our 2014 capital development plans.

In connection with the issuance of the August Notes, we and the subsidiary guarantors entered into a registration rights agreement with the initial purchasers on August 18, 2014, pursuant to which we and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the August Notes for a new issue of substantially identical debt securities registered under the Securities Act. The registration statement relating to the exchange offer for the August Notes was filed on November 6, 2014, as amended on February 3, 2015, and declared effective by the SEC on February 4, 2015. The exchange offer for the August Note is expected to be completed on or about March 10, 2015.

Under the senior note indenture, interest on the Exchange Notes and the August Notes (which we refer together as the Notes) accrues at a rate of 7.75% 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 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.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions (primarily in the Utica Shale), 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, (2) pursue acquisition and disposition opportunities and (3) pursue business integration opportunities.

Of our net reserves at December 31, 2014, 51.4% 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.

During 2014, we spud 85 gross (67.2 net) wells in the Utica Shale for a total cost of approximately \$583.5 million. We currently expect our 2015 capital expenditures to be \$400.0 million to \$430.0 million to drill 46 to 52 gross (28 to 32 net) horizontal wells and commence sales from 49 to 53 gross (42 to 46 net) wells on our Utica Shale acreage. As of February 25, we had four operated horizontal rigs drilling in the play, but plan to release one of these rigs by the end of the first quarter 2015. We also anticipate an additional 11 to 16 gross (four to six net) horizontal wells will be drilled, and sales commenced from 50 to 64 gross (seven to nine net) horizontal wells, on our Utica Shale acreage by other operators for estimated 2015 expenditures of \$125.0 million to \$140.0 million. In addition, we currently expect to spend \$85.0 million to \$95.0 million in 2015 to acquire additional acreage in the Utica Shale.

During 2014, we recompleted 91 existing wells and spud 29 new wells for a total cost of approximately \$70.0 million at our WCBB field. In our Hackberry fields, in 2014, we recompleted 70 existing wells and spud 16 new wells for a total cost of approximately \$43.4 million. We currently expect our 2015 capital expenditures to be \$20.0 million to \$25.0 million for maintenance capital expenditures and recompletions in Southern Louisiana.

During 2014, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2015.

During the third quarter of 2006, we purchased a 24.9% interest in Grizzly. As of December 31, 2014, our net investment in Grizzly was approximately \$180.2 million. Our capital requirements in 2014 for Grizzly were approximately \$18.8 million, primarily for the expenses associated with the construction of the Algar Lake facility. Effective October 5, 2012, Grizzly entered into a \$125.0 million revolving credit facility, of which \$75.0 million has been borrowed to fund additional infrastructure relating to the Algar Lake facility and other future development projects. We do not currently anticipate any material capital expenditures in 2015 related to Grizzly's activities.

We had capital expenditures of approximately \$1.2 million during the year ended December 31, 2014 related to our interests in Thailand. We do not currently anticipate any capital expenditures in Thailand in 2015.

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 2013, we participated in the formation of Stingray Energy with an initial ownership interest of 50%. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. In 2012, we participated in the formation of Stingray Pressure, Stingray Cementing, and Stingray Logistics, with an initial ownership interest in each entity of 50%. These entities provide well completion and other well services. In 2012, we also participated in the formation of Blackhawk and Timber Wolf with an initial ownership interest of 50% in each entity. Blackhawk coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage and Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. Also in 2012, we acquired a 22.5% equity interest in Midstream which owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011 and 2012, we acquired an aggregate 40% equity interest in Bison which owns and operates drilling rigs and related equipment. Also in 2011, we acquired a 25% interest in Muskie which is engaged in the processing and sale of hydraulic fracturing grade sand. In 2014, we acquired a 25% equity interest in Sturgeon which owns and operates sand mines that produce hydraulic fracturing grade sand. See Note 5 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments. During the year ended December 31, 2014, we invested approximately \$43.6 million in these entities. In 2015, we do not currently anticipate any capital expenditures related to these entities. We are currently evaluating strategic alternatives with respect to these oil field service entities. In the fourth quarter of 2014, we contributed our investments in Stingray Pressure, Stingray Logistics, Bison and Muskie to Mammoth in exchange for a 30.5% limited partner interest in this newly formed limited partnership. Mammoth has filed a registration statement on Form S-1 with the SEC in connection with its contemplated initial public offering which it intends to pursue in 2015 subject to market conditions. In January 2014, Blackhawk completed the sale of its equity interests in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC for a purchase price of \$190.0 million, of which we received \$84.8 million in net proceeds. Subsequent to December 31, 2014, we received net proceeds of \$7.2 million from the release of escrow from the Blackhawk sale.

Our total capital expenditures for 2015 are currently estimated to be in the range of \$545.0 million to \$595.0 million. In addition, we currently expect to spend \$85.0 million to \$95.0 million in 2015 to acquire additional Utica Shale acreage. Approximately 96% of our 2015 estimated capital expenditures are currently expected to be spent in the Utica Shale. This range is down from the \$872.9 million spent in 2014, excluding Utica leasehold acquisitions and the Rhino acquisition, primarily due to current commodity prices and a desire to maintain a strong liquidity position. During 2014, we continued to focus on operational efficiencies in an effort to reduce our overall well costs. Further, due in large part to the significant decline in commodity prices, we have been able to negotiate reductions in service costs with our vendors. We continue to see

improvement in our service costs and expect that our operational efficiencies, combined with our service costs reductions, will lower our overall well costs by approximately 15% during 2015. 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, the January 2015 escrow distribution from Blackhawk 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 program or pursue additional acquisitions, or Grizzly's oil sands projects require additional investments, 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. During the past six years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, has ranged from a low of \$34.03 per barrel, or Bbl, in February 2009 to a high of \$113.39 per Bbl in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of \$1.82 per MMBtu in April 2012 to a high of \$7.51 per MMBtu in January 2010. During 2014, WTI prices ranged from \$52.87 to \$100.54 per Bbl and the Henry Hub spot market price of natural gas ranged from \$2.89 to \$4.91 per MMBtu. On January 20, 2015, the WTI posted price for crude oil was \$46.47 per Bbl and the Henry Hub spot market price of natural gas was \$2.82 per MMBtu, representing decreases of 54% and 43%, respectively, from the high of \$100.54 per Bbl of oil and \$4.91 per MMBtu for natural gas during 2014. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. 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 activities are curtailed, 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. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

See Item 7A. Quantitative and Qualitative Disclosures about Market Risk for information regarding our open fixed price swaps at December 31, 2014.

Commitments

In connection with our 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, 2014, the plugging and abandonment trust totaled approximately \$3.1 million. At December 31, 2014, we have plugged 450 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

Contractual and Commercial Obligations

The following table sets forth our contractual and commercial obligations at December 31, 2014:

<u>Contractual Obligations</u>	Payment due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
7.75% senior unsecured notes due 2020 (1)	\$ 877,127	\$ 46,500	\$ 93,000	\$ 93,000	\$ 644,627
Revolving credit agreement	100,000	—	—	100,000	—
Asset retirement obligations	17,938	75	474	852	16,537
Employment agreements	933	400	533	—	—
Building loan (2)	1,826	168	1,658	—	—
Firm transportation contracts	2,403,828	83,871	261,064	289,120	1,769,773
Purchase obligations (3)	196,650	52,440	104,880	39,330	—
Operating leases	1,610	615	975	20	—
Total	\$ 3,599,912	\$ 184,069	\$ 462,584	\$ 522,322	\$ 2,430,937

(1) Includes estimated interest of \$46.5 million due in less than one year; \$93.0 million due in 1-3 years; \$93.0 million due in 3-5 years and \$44.6 million due thereafter.

(2) Does not include estimated interest of \$102,000 due in less than one year and \$16,000 due in 1-3 years.

(3) The purchasing obligations reported above represent our minimum financial commitment pursuant to the terms of these contracts.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of December 31, 2014.

New Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360) - Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. ASU 2014-08 changes the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other material disposal transactions that do not meet the revised definition of a discontinued operation. Under the updated standard, a disposal of a component or group of components of an entity is required to be reported as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component or group of components of the entity (1) has been disposed of by a sale, (2) has been disposed of other than by sale or (3) is classified as held for sale. The ASU is effective for annual and interim periods beginning after December 15, 2014, however, early adoption is permitted. We early adopted this ASU on a prospective basis beginning with the second quarter of 2014. The adoption did not have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers*, which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years, using either a full or a modified retrospective application approach. We are in the process of evaluating the impact on our consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014-15, "*Presentation of Financial Statements - Going Concern (Subtopic 205-40)*." The new guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and in certain circumstances to provide related footnote disclosures. The standard is effective for the annual period ending after December 15, 2016 and for annual and interim periods thereafter. Early adoption is permitted. We do not believe that the adoption of this guidance will have a material impact on our 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. During the past six years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as West Texas

Intermediate or WTI, has ranged from a low of \$34.03 per barrel, or Bbl, in February 2009 to a high of \$113.39 per Bbl in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of \$1.82 per MMBtu in April 2012 to a high of \$7.51 per MMBtu in January 2010. During 2014, WTI prices ranged from \$52.87 to \$100.54 per Bbl and the Henry Hub spot market price of natural gas ranged from \$2.89 to \$4.91 per MMBtu. On January 20, 2015, the WTI posted price for crude oil was \$46.47 per Bbl and the Henry Hub spot market price of natural gas was \$2.82 per MMBtu, representing decreases of 54% and 43%, respectively, from the high of \$100.54 per Bbl of oil and \$4.91 per MMBtu for natural gas during 2014. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. 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 activities are curtailed, 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. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

To mitigate the effects of commodity price fluctuations on our oil and natural gas production, we had the following open fixed price swaps and swaptions at December 31, 2014:

	Volume (MMBtu per day)	Weighted Average Price (\$ per MMBtu)
Fixed Price Swaps and Swaptions:		
January 2015 - March 2015	190,625	\$ 4.12
April 2015	191,250	\$ 4.05
May 2015 - June 2015	201,250	\$ 4.05
July 2015 - September 2015	216,875	\$ 4.04
October 2015 - December 2015	232,500	\$ 4.04
January 2015 - March 2016	172,500	\$ 3.99
April 2016	162,500	\$ 3.99
May 2016 - December 2016	92,500	\$ 3.97
January 2017 - June 2017	62,500	\$ 3.96

In January and February of 2015, we entered into fixed price swaps for 1,000 barrels of oil per day at a weighted average price of \$62.25 per barrel. For the period of September 2015 through December 2015, we entered into fixed price swaps for 30,000 MMBtu of natural gas per day at a weighted average price of \$3.40 per MMBtu. For the period from January 2016 through December 2017, we entered into fixed price swaps for 80,000 MMBtu of natural gas per day at a weighted average

price of \$3.45 per MMBtu. For the period from January 2018 through December 2018, we entered into fixed price swaps for 30,000 MMBtu of natural gas per day at a weighted average price of \$3.40 per MMBtu. Our fixed price swap contracts are tied to the commodity prices on NYMEX. We will receive the fixed price amount stated in the contract and pay to our counterparty the current market price as listed on NYMEX for natural gas.

In February 2015, we entered into natural gas basis swap positions, which settle on the pricing index to basis differential of MichCon to the NYMEX Henry Hub natural gas price for 30,000 MMBtu per day at a hedge differential of \$.02 for the period from March 2015 through December 2016 and for 10,000 MMBtu per day at a hedge differential of \$.01 for the period from March 2015 through December 2016.

Under our 2015 contracts, we have hedged approximately 47% to 52% of our expected 2015 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, 2014, we had a net asset derivative position of \$102.8 million as compared to a net liability derivative position of \$22.8 million as of December 31, 2013, 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 \$42.1 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately \$42.1 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. At December 31, 2014, amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 1.91%. A 1% increase in interest rates would increase interest expense by approximately \$1.0 million per year, based on \$100.0 million outstanding under our revolving credit facility as of December 31, 2014. As of December 31, 2014, 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 President and our 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 President and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of December 31, 2014, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and President and our 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 President and our Chief Financial Officer have concluded that, as of December 31, 2014, 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.

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 the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the 2013 *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, 2014.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2014 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2014, as stated in their accompanying report.

/s/ Michael G. Moore

Name: Michael G. Moore

Title: Chief Executive Officer and President

/s/ Aaron Gaydosik

Name: Aaron Gaydosik

Title: Chief Financial Officer

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, 2014, based on criteria established in the 2013 *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, 2014, based on criteria established in the 2013 *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, 2014 and our report dated February 27, 2015 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 27, 2015

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).

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report or incorporated by reference herein:

(1) *Financial Statements*

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

Reference is also made to the Financial Statements of Diamondback Energy, Inc. (“Diamondback”) that have been included on pages F-1 to F-54 in Diamondback’s Annual Report on Form 10-K (File No. 001-35700) filed with the SEC on February 20, 2015, as such Annual Report on Form 10-K may be amended from time to time, which Financial Statements are incorporated herein by reference.

(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	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).
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	Certificate of Amendment No. 2 to 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 July 23, 2013).
3.4	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).
3.5	First Amendment to the 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 23, 2013).
3.6	Second Amendment to the Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on May 2, 2014).
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	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).
4.3	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).
4.4	Second Supplemental Indenture, dated August 18, 2014, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on August 19, 2014).
4.5	Registration Rights Agreement, dated as of August 18, 2014, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.4 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on August 19, 2014).

- 10.1+ 2013 Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form S-4, File No. 333-189992, filed by the Company with the SEC on July 17, 2013).
- 10.2+ 2014 Executive Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 7, 2014).
- 10.3+* 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).
- 10.4+ Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to the Form 10-K, File No. 000-19514, filed by the Company with the SEC on February 28, 2014).
- 10.5+ Consulting Agreement, effective as of June 14, 2013, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on June 19, 2013).
- 10.6+ Separation and Release Agreement, dated as of January 31, 2014, by and between the Company and James D. Palm (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 4, 2014).
- 10.7+ Employment Agreement, entered into on April 30, 2014, by and between Gulfport Energy Corporation and Michael G. Moore (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S-4/A, File No. 333-199905, filed by the Company with the SEC on February 3, 2015).
- 10.8 Amended and Restated Credit Agreement, dated as of December 27, 2013, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 3, 2014).
- 10.9 First Amendment to Amended and Restated Credit Agreement, dated as of April 23, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 28, 2014).
- 10.10 Second Amendment to Amended and Restated Credit Agreement, dated as of November 26, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 3, 2014).
- 10.11# Sand Supply Agreement, effective as of October 1, 2014, by and between Muskie Proppant LLC and Gulfport Energy Corporation (incorporated by reference to Exhibit 10.1 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 7, 2014).
- 10.12# Amended and Restated Master Services Agreement, effective as of October 1, 2014, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 7, 2014).
- 10.13+ Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-4, File No. 333-199905, filed by the Company with the SEC on November 6, 2014).
- 10.14 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 Ryder Scott Company.
- 23.3* Consent of Netherland, Sewell & Associates, Inc.

- 23.4* Consent of Grant Thornton LLP with respect to financial statements of Diamondback Energy, Inc.
 - 31.1* Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
 - 31.2* Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
 - 32.1** Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
 - 32.2** Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
 - 99.1* Report of Ryder Scott Company.

 - 99.2* Report of Netherland, Sewell & Associates, Inc.
 - 101.INS* XBRL Instance Document.
 - 101.SCH* XBRL Taxonomy Extension Schema Document.
 - 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.
- # Confidential treatment with respect to certain portions of this agreement was granted by the SEC on January 16, 2015, which portions have been omitted and filed separately with the SEC.

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 (a Delaware Corporation) and subsidiaries (the “Company”) as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, 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, 2014, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2015 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 27, 2015

GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
(In thousands, except share data)		
Assets		
Current assets:		
Cash and cash equivalents	\$ 142,340	\$ 458,956
Accounts receivable—oil and gas	103,858	58,824
Accounts receivable—related parties	46	2,617
Prepaid expenses and other current assets	3,714	2,581
Deferred tax asset	—	6,927
Short-term derivative instruments	78,391	324
Note receivable - related party	—	875
Total current assets	328,349	531,104
Property and equipment:		
Oil and natural gas properties, full-cost accounting, \$1,465,538 and \$1,020,835 excluded from amortization in 2014 and 2013, respectively	3,923,154	2,477,178
Other property and equipment	18,344	11,131
Accumulated depletion, depreciation, amortization and impairment	(1,050,879)	(784,717)
Property and equipment, net	2,890,619	1,703,592
Other assets:		
Equity investments (\$0 and \$178,708 attributable to fair value option in 2014 and 2013, respectively)	369,581	440,068
Derivative instruments	24,448	521
Other assets	19,396	17,851
Total other assets	413,425	458,440
Total assets	\$ 3,632,393	\$ 2,693,136
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 371,410	\$ 190,707
Asset retirement obligation—current	75	795
Short-term derivative instruments	—	12,280
Deferred tax liability	27,070	—
Current maturities of long-term debt	168	159
Total current liabilities	398,723	203,941
Long-term derivative instrument	—	11,366
Asset retirement obligation—long-term	17,863	14,288
Deferred tax liability	203,195	114,275
Long-term debt, net of current maturities	716,316	299,028
Total liabilities	1,336,097	642,898
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, 200,000,000 authorized, 85,655,438 issued and outstanding in 2014 and 85,177,532 in 2013	856	851
Paid-in capital	1,828,602	1,813,058
Accumulated other comprehensive loss	(26,675)	(9,781)
Retained earnings	493,513	246,110
Total stockholders' equity	2,296,296	2,050,238
Total liabilities and stockholders' equity	\$ 3,632,393	\$ 2,693,136

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
	2014	2013	2012
(In thousands, except share data)			
Revenues:			
Oil and condensate sales	\$ 247,381	\$ 224,129	\$ 242,708
Gas sales	329,254	21,015	3,225
Natural gas liquid sales	94,127	17,081	2,668
Other income	504	528	325
	<u>671,266</u>	<u>262,753</u>	<u>248,926</u>
Costs and expenses:			
Lease operating expenses	52,191	26,703	24,308
Production taxes	24,006	26,933	28,957
Midstream gathering and processing	64,467	11,030	443
Depreciation, depletion and amortization	265,431	118,880	90,749
General and administrative	38,290	22,519	13,808
Accretion expense	761	717	698
(Gain) loss on sale of assets	(11)	508	(7,300)
	<u>445,135</u>	<u>207,290</u>	<u>151,663</u>
INCOME FROM OPERATIONS	<u>226,131</u>	<u>55,463</u>	<u>97,263</u>
OTHER (INCOME) EXPENSE:			
Interest expense	23,986	17,490	7,458
Interest income	(195)	(297)	(72)
Litigation settlement	25,500	—	—
Gain on contribution of investments	(84,470)	—	—
Income from equity method investments	(139,434)	(213,058)	(8,322)
	<u>(174,613)</u>	<u>(195,865)</u>	<u>(936)</u>
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	<u>400,744</u>	<u>251,328</u>	<u>98,199</u>
INCOME TAX EXPENSE	<u>153,341</u>	<u>98,136</u>	<u>26,363</u>
INCOME FROM CONTINUING OPERATIONS	<u>247,403</u>	<u>153,192</u>	<u>71,836</u>
DISCONTINUED OPERATIONS			
Loss on disposal of Belize properties, net of tax	—	—	3,465
NET INCOME	<u>\$ 247,403</u>	<u>\$ 153,192</u>	<u>\$ 68,371</u>
NET INCOME PER COMMON SHARE:			
Basic net income from continuing operations per share	\$ 2.90	\$ 1.98	\$ 1.28
Basic net income from discontinued operations, net of tax, per share	—	—	(0.06)
Basic net income per share	<u>\$ 2.90</u>	<u>\$ 1.98</u>	<u>\$ 1.22</u>
Diluted net income from continuing operations per share	\$ 2.88	\$ 1.97	\$ 1.27
Diluted net income from discontinued operations, net of tax, per share	—	—	(0.06)
Diluted net income per share	<u>\$ 2.88</u>	<u>\$ 1.97</u>	<u>\$ 1.21</u>
Weighted average common shares outstanding—Basic	85,445,963	77,375,683	55,933,354
Weighted average common shares outstanding—Diluted	85,813,182	77,861,646	56,417,488

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	<u>For the Year Ended December 31,</u>		
	<u>2014</u>	<u>2013</u>	<u>2012</u>
	(In thousands)		
Net income	\$ 247,403	\$ 153,192	\$ 68,371
Foreign currency translation adjustment	(16,894)	(12,223)	1,355
Change in fair value of derivative instruments (1)	—	(4,419)	(8,452)
Reclassification of settled contracts (2)	—	10,290	1,005
Other comprehensive loss	(16,894)	(6,352)	(6,092)
Comprehensive income	<u>\$ 230,509</u>	<u>\$ 146,840</u>	<u>\$ 62,279</u>

(1) Net of \$4.3 million and \$(4.3) million in taxes for the years ended December 31, 2013 and 2012, respectively. No taxes were recorded in the year ended 2014.

(2) Net of \$(0.5) million and \$0.5 million in taxes for the years ended December 31, 2013 and 2012, respectively. No taxes were recorded in the year ended 2014.

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Stockholders' Equity
	Shares	Amount				
(In thousands, except share data)						
Balance at January 1, 2012	55,621,371	\$ 556	\$ 604,584	\$ 2,663	\$ 24,547	\$ 632,350
Net income	—	—	—	—	68,371	68,371
Other Comprehensive Loss	—	—	—	(6,092)	—	(6,092)
Stock Compensation	—	—	4,688	—	—	4,688
Issuance of Common Stock in public offerings, net of related expenses	11,750,000	118	426,789	—	—	426,907
Issuance of Restricted Stock	135,015	—	—	—	—	—
Issuance of Common Stock through exercise of options	21,000	—	184	—	—	184
Balance at December 31, 2012	<u>67,527,386</u>	<u>674</u>	<u>1,036,245</u>	<u>(3,429)</u>	<u>92,918</u>	<u>1,126,408</u>
Net income	—	—	—	—	153,192	153,192
Other Comprehensive Loss	—	—	—	(6,352)	—	(6,352)
Stock Compensation	—	—	10,495	—	—	10,495
Issuance of Common Stock in public offerings, net of related expenses	17,287,500	173	764,922	—	—	765,095
Issuance of Restricted Stock	237,646	3	(3)	—	—	—
Issuance of Common Stock through exercise of options	125,000	1	1,399	—	—	1,400
Balance at December 31, 2013	<u>85,177,532</u>	<u>851</u>	<u>1,813,058</u>	<u>(9,781)</u>	<u>246,110</u>	<u>2,050,238</u>
Net income	—	—	—	—	247,403	247,403
Other Comprehensive Loss	—	—	—	(16,894)	—	(16,894)
Stock Compensation	—	—	14,860	—	—	14,860
Issuance of Restricted Stock	272,665	3	(3)	—	—	—
Issuance of Common Stock through exercise of options	205,241	2	687	—	—	689
Balance at December 31, 2014	<u>85,655,438</u>	<u>\$ 856</u>	<u>\$ 1,828,602</u>	<u>\$ (26,675)</u>	<u>\$ 493,513</u>	<u>\$ 2,296,296</u>

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2014	2013	2012
(In thousands)			
Cash flows from operating activities:			
Net income	\$ 247,403	\$ 153,192	\$ 68,371
Adjustments to reconcile net income to net cash provided by operating activities:			
Accretion of discount—Asset Retirement Obligation	761	717	698
Depletion, depreciation and amortization	265,431	118,880	90,749
Stock-based compensation expense	8,916	6,297	2,813
Gain from equity investments	(54,171)	(212,714)	(8,322)
Gain on contribution of investments	(84,470)	—	—
Interest income - note receivable	(46)	(26)	(2)
Unrealized (gain) loss on derivative instruments	(121,148)	18,189	144
Deferred income tax expense	122,917	84,951	24,120
Amortization of loan commitment fees	1,685	1,012	640
Amortization of note discount and premium	(533)	298	59
Write off of loan commitment fees	—	—	1,143
Loss on disposal of assets	—	—	5,702
Gain on sale of assets	—	—	(7,300)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(45,034)	(33,209)	2,404
Decrease (increase) in accounts receivable—related party	2,571	32,231	(30,117)
Increase in prepaid expenses	(1,133)	(1,075)	(179)
Increase in other assets	—	(4,523)	—
Increase in accounts payable and accrued liabilities	73,925	29,310	50,506
Settlement of asset retirement obligation	(7,201)	(2,465)	(2,271)
Net cash provided by operating activities	<u>409,873</u>	<u>191,065</u>	<u>199,158</u>
Cash flows from investing activities:			
Deductions to cash held in escrow	8	8	8
Additions to other property and equipment	(7,030)	(2,322)	(638)
Additions to oil and gas properties	(1,329,277)	(808,183)	(757,192)
Proceeds from sale of other property and equipment	—	113	140
Proceeds from sale of oil and gas properties	4,404	—	63,590
Repayments (advances) on note receivable to related party	875	(875)	—
Proceeds from sale of investments	258,362	192,737	—
Contributions to equity method investments	(63,999)	(47,014)	(147,307)
Distributions from equity method investments	—	1,276	820
Net cash used in investing activities	<u>(1,136,657)</u>	<u>(664,260)</u>	<u>(840,579)</u>
Cash flows from financing activities:			
Principal payments on borrowings	(115,690)	(149)	(158,639)
Borrowings on line of credit	215,000	—	158,500
Proceeds from bond issuance	318,000	—	296,835
Debt issuance costs and loan commitment fees	(7,831)	(1,283)	(9,175)
Proceeds from issuance of common stock, net of offering costs	689	766,495	427,091
Net cash provided by financing activities	<u>410,168</u>	<u>765,063</u>	<u>714,612</u>
Net (decrease) increase in cash and cash equivalents	<u>(316,616)</u>	<u>291,868</u>	<u>73,191</u>
Cash and cash equivalents at beginning of period	458,956	167,088	93,897
Cash and cash equivalents at end of period	<u>\$ 142,340</u>	<u>\$ 458,956</u>	<u>\$ 167,088</u>
Supplemental disclosure of cash flow information:			
Interest payments	<u>\$ 28,646</u>	<u>\$ 24,280</u>	<u>\$ 1,461</u>
Income tax payments	<u>\$ 23,800</u>	<u>\$ 2,761</u>	<u>\$ 261</u>
Supplemental disclosure of non-cash transactions:			
Capitalized stock based compensation	<u>\$ 5,944</u>	<u>\$ 4,198</u>	<u>\$ 1,875</u>
Asset retirement obligation capitalized	<u>\$ 9,295</u>	<u>\$ 3,556</u>	<u>\$ 2,195</u>
Interest capitalized	<u>\$ 9,687</u>	<u>\$ 7,132</u>	<u>\$ —</u>
Foreign currency translation (loss) gain on investment in Grizzly Oil Sands ULC	<u>\$ 16,894</u>	<u>\$ (12,223)</u>	<u>\$ 1,355</u>

See accompanying notes to consolidated financial statements.



GULFPORT ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2014, 2013 AND 2012

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 Utica Shale primarily in Eastern Ohio, along the Louisiana Gulf Coast and in Western Colorado in the Niobrara Formation, and has investments in companies operating in the United States, 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 three purchasers of the Company’s oil and gas and receivables from joint interest owners on properties the Company operates. 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, 2014 and December 31, 2013.

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 2014, 2013 and 2012, 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 barrels to gas at the ratio of one barrel of oil to six Mcf of gas. 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 \$1.5 billion and \$1.0 billion at December 31, 2014 and December 31, 2013, 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 and equity contributions are translated at the current exchange rate in effect at the date of the contribution. 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 (loss).

	(In thousands)
December 31, 2011	\$ 1,087
December 31, 2012	\$ 2,442
December 31, 2013	\$ (9,781)
December 31, 2014	\$ (26,675)

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 1999 – 2014 U.S. federal and state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2014, 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, 2014, there is no interest or penalties associated with uncertain tax positions in the Company's consolidated financial statements.

Revenue Recognition

Natural 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, 2014 and 2013, the Company had no gas imbalance liability. Oil revenues are recognized when ownership transfers, which occurs in the month produced.

Investments—Equity Method

Investments in entities in which the Company owns an equity interest greater than 20% and less than 50% and/or investments in which it has significant influence 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 the common stock of Diamondback Energy Inc. ("Diamondback"). At the end of each reporting period, the quoted closing market price of Diamondback's common stock is multiplied by the total shares owned by the Company and the resulting gain or loss is recognized in income from equity method investments in the consolidated statements of operations. As of December 31, 2014, the Company did not own any shares of Diamondback's common stock.

The Company reviews its investments annually 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, 2013. At December 31, 2014, the Company recognized an impairment of \$12.1 million related to its investment in Tatex Thailand III, LLC. See Note 5 for further discussion of this impairment.

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 one 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 and natural gas prices by utilizing energy swaps and collars. 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 April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360) - Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. ASU 2014-08 changes the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other material disposal transactions that do not meet the revised definition of a discontinued operation. Under the updated standard, a disposal of a component or group of components of an entity is required to be reported as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component or group of components of the entity (1) has been disposed of by a sale, (2) has been disposed of other than by sale or (3) is classified as held for sale. The ASU is effective for annual and interim periods beginning after December 15, 2014, however, early adoption is permitted. The Company early adopted this ASU on a prospective basis beginning with the second quarter of 2014. The adoption did not have a material impact on the Company's consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition*, and most industry-specific guidance. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years, using either a full or a modified retrospective application approach. The Company is in the process of evaluating the impact on its consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements - Going Concern (Subtopic 205-40)*. The new guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and in certain circumstances to provide related footnote disclosures. The standard is effective for the annual period ending after December 15, 2016 and for annual and interim periods thereafter. Early adoption is permitted. The Company does not believe that the adoption of this guidance will have a material impact on its consolidated financial statements.

In February 2013, the FASB issued 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. Adoption of the provisions of this ASU did not have a material effect on the Company's 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 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 granted the Company an exclusive right of first refusal for a period of six months to acquire certain additional tracts leased by the seller. Certain entities that, at the time, were 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 with one of the affiliates to purchase approximately 30,000 net acres in the Utica Shale 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. Gulfport funded this acquisition with a portion of the net proceeds from its common stock offering that closed on December 24, 2012 (with a second closing for the underwriters' purchase of 900,000 shares pursuant to their over-allotment option on January 7, 2013). The Company received aggregate net proceeds of approximately \$460.7 million from this equity offering, as discussed below in Note 8.

On February 15, 2013, the Company completed an acquisition of approximately 22,000 net acres in the Utica Shale. The purchase price was approximately \$220.0 million, subject to certain adjustments. At closing, approximately \$33.6 million of the purchase price was placed in escrow pending completion of title review after the closing. Gulfport funded this acquisition with a portion of the net proceeds from its common stock offering that closed on February 15, 2013. The Company received aggregate net proceeds of approximately \$325.8 million from this equity offering. All of the acreage included in these transactions was nonproducing at the time of the applicable transaction and the Company is the operator of all of this acreage, subject to existing development and operating agreements between the parties. These acquisitions excluded the seller's interest in 14 existing wells and 16 proposed future wells together with certain acreage surrounding these wells.

In May 2013, both escrow accounts terminated and an aggregate of \$10.0 million was returned to the Company. The balance of the escrow accounts was distributed to the seller based on the results of the title review.

In February 2014, the Company entered into a definitive agreement with Rhino Exploration LLC ("Rhino") to acquire additional oil and natural gas properties consisting of approximately 8,000 net acres in the Utica Shale, as well as Rhino's interest in all of the producing wells on this acreage (the "Rhino Acquisition"). The Company purchased approximately \$182.0 million (\$179.5 million net of purchase price adjustments) of these assets in 2014. The Company recognized \$6.4 million of net revenues and \$1.0 million of lease operating expenses as a result of the Rhino Acquisition from the closing date of March 20, 2014 through December 31, 2014, which is included in the accompanying consolidated statements of operations.

The Rhino Acquisition qualified as a business combination for accounting purposes and, as such, the Company estimated the fair value of the acquired properties as of the March 20, 2014 acquisition date. The fair value of the assets and liabilities acquired was estimated using assumptions that represent Level 3 inputs. See "Note 14 - Fair Value Measurements" for additional discussion of the measurement inputs.

The Company estimated that the consideration paid in the Rhino Acquisition for these properties approximated the fair value that would be paid by a typical market participant. As a result, no goodwill or bargain purchase gain was recognized in conjunction with the purchase.

The following table summarizes the consideration paid in the Rhino Acquisition to acquire the properties and the fair value amount of the assets acquired as of March 20, 2014.

	(in thousands)	
Consideration paid		
Cash, net of purchase price adjustments	\$	179,527
Fair value of identifiable assets acquired		
Oil and natural gas properties		
Proved	\$	31,961
Unproved		6,263
Unevaluated		141,303
Fair value of net identifiable assets acquired	\$	<u>179,527</u>

3. ACCOUNTS RECEIVABLE—RELATED PARTIES

Included in the accompanying consolidated balance sheets as of December 31, 2014 and 2013 are amounts receivable from related parties of the Company. At December 31, 2013, these receivables totaled \$2.6 million. At December 31, 2014, the amount of related party receivables was immaterial.

4. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2014 and 2013 are as follows:

	December 31,	
	2014	2013
	(In thousands)	
Oil and natural gas properties	\$ 3,923,154	\$ 2,477,178
Office furniture and fixtures	10,752	6,093
Building	5,398	4,626
Land	2,194	412
Total property and equipment	<u>3,941,498</u>	<u>2,488,309</u>
Accumulated depletion, depreciation, amortization and impairment	<u>(1,050,879)</u>	<u>(784,717)</u>
Property and equipment, net	<u>\$ 2,890,619</u>	<u>\$ 1,703,592</u>

No impairment of oil and natural gas properties was required under the ceiling test for the years ended December 31, 2014, 2013 or 2012.

Included in oil and natural gas properties at December 31, 2014 and 2013 is the cumulative capitalization of \$72.7 million and \$47.5 million in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately \$25.2 million, \$14.9 million and \$9.1 million for the years ended December 31, 2014, 2013 and 2012, respectively.

The following is a summary of Gulfport's oil and gas properties not subject to amortization as of December 31, 2014:

	Costs Incurred in				
	2014	2013	2012	Prior to 2012	Total
	(in thousands)				
Acquisition costs	\$ 405,226	\$ 323,515	\$ 459,151	\$ 93,864	\$ 1,281,756
Exploration costs	—	—	—	—	—
Development costs	173,693	1,801	506	—	176,000
Capitalized interest	5,204	2,578	—	—	7,782
Total oil and gas properties not subject to amortization	\$ 584,123	\$ 327,894	\$ 459,657	\$ 93,864	\$ 1,465,538

The following table summarizes the Company's non-producing properties excluded from amortization by area at December 31, 2014:

	December 31, 2014
	(In thousands)
Colorado	\$ 5,127
Bakken	96
Southern Louisiana	145
Ohio	1,460,125
Other	45
	\$ 1,465,538

At December 31, 2013, approximately \$1.0 billion of non-producing leasehold costs was not subject to amortization.

During the year ended December 31, 2012, the Company determined that further development of its non-producing leasehold assets located in Belize was not in alignment with its strategic operating plan and, therefore, recognized a loss on disposal of assets, net of tax, of approximately \$3.5 million which is included in discontinued operations on the accompanying consolidated statements of operations for the year ended December 31, 2012.

The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company's activities, the inclusion of most of the above referenced costs into the Company's amortization calculation is expected to occur within three to five years.

A reconciliation of the Company's asset retirement obligation for the years ended December 31, 2014 and 2013 is as follows:

	December 31,	
	2014	2013
	(In thousands)	
Asset retirement obligation, beginning of period	\$ 15,083	\$ 13,275
Liabilities incurred	9,295	3,556
Liabilities settled	(7,201)	(2,465)
Accretion expense	761	717
Asset retirement obligation as of end of period	17,938	15,083
Less current portion	75	795
Asset retirement obligation, long-term	\$ 17,863	\$ 14,288

On May 7, 2012, the Company entered into a contribution agreement with Diamondback. Under the terms of the contribution agreement, the Company agreed to contribute to Diamondback, prior to the closing of the Diamondback initial public offering ("Diamondback IPO"), all its oil and natural gas interests in the Permian Basin (the "Contribution"). The Contribution was completed on October 11, 2012. At the closing of the Contribution, Diamondback issued to the Company (i)

7,914,036 shares of Diamondback common stock and (ii) a promissory note for \$63.6 million, which was repaid to the Company 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 Diamondback O&G LLC, formerly Windsor Permian LLC ("Diamondback O&G"), as of the date of the Contribution. In January 2013, the Company received an additional payment from Diamondback of approximately \$18.6 million as a result of this post-closing adjustment. Diamondback O&G is a wholly-owned subsidiary of Diamondback. Under the contribution agreement, the Company is generally responsible for all liabilities and obligations with respect to the contributed properties arising prior to the Contribution and Diamondback is responsible for such liabilities and obligations with respect to the contributed properties arising after the Contribution.

In accordance with the Company's policy under the full cost method of accounting to only recognize a gain or loss upon the disposal of oil and natural gas properties if such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves, the Company recognized a gain on the sale of its Permian Basin assets of approximately \$7.3 million, which is included in the accompanying consolidated statements of operations for the year ended December 31, 2012. In addition, the Company recorded a reduction to its full cost pool of approximately \$213.0 million as a result of the Contribution.

In connection with the Contribution, the Company and Diamondback entered into an investor rights agreement under which the Company had the right, for so long as it beneficially owned 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, would also serve on each committee of the board so long as he or she satisfied the independence and other requirements for service on the applicable committee of the board. So long as the Company had the right to designate a nominee to Diamondback's board and there was no Gulfport nominee actually serving as a Diamondback director, the Company had the right to appoint one individual as an advisor to the board who would be entitled to attend board and committee meetings. The Company was also entitled to certain information rights and Diamondback granted the Company certain demand and "piggyback" registration rights obligating Diamondback to register with the SEC any shares of Diamondback common stock that the Company owns. Immediately upon completion of the Contribution, the Company owned a 35% equity interest in Diamondback, rather than leasehold interests in the Company's Permian Basin acreage. Upon completion of the Diamondback IPO in October 2012, Gulfport owned approximately 21.4% of Diamondback's outstanding common stock. Following the Contribution, the Company has accounted for its interest in Diamondback as an equity investment. In November 2014, the Company sold all of the remaining shares of Diamondback common stock that it received in the Contribution and, as of December 31, 2014, Gulfport did not own any shares of Diamondback's common stock. See Note 5, "Equity Investments - *Diamondback Energy, Inc.*"

5. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2014 and 2013:

	Approximate Ownership %	Carrying Value		(Income) loss from equity method investments		
		December 31,		For the Year Ended December 31,		
		2014	2013	2014	2013	2012
(In thousands)						
Investment in Tatex Thailand II, LLC	23.5%	\$ —	\$ —	\$ (475)	\$ (343)	\$ 7
Investment in Tatex Thailand III, LLC	17.9%	—	10,774	12,408	254	251
Investment in Grizzly Oil Sands ULC	24.9999%	180,218	191,473	13,159	2,999	1,512
Investment in Bison Drilling and Field Services LLC	—%	—	12,318	213	3,533	373
Investment in Muskie Proppant LLC	—%	—	7,544	371	1,975	1,031
Investment in Timber Wolf Terminals LLC	50.0%	1,013	1,001	9	(6)	122
Investment in Windsor Midstream LLC	22.5%	13,505	10,632	(477)	(1,125)	(663)
Investment in Stingray Pressure Pumping LLC	—%	—	19,624	2,027	(818)	1,235
Investment in Stingray Cementing LLC	50.0%	2,647	3,291	344	93	159
Investment in Blackhawk Midstream LLC	—%	—	—	(84,787)	673	436
Investment in Stingray Logistics LLC	50.0%	—	903	(464)	51	36
Investment in Diamondback Energy, Inc.	—%	—	178,708	(79,654)	(220,129)	(12,821)
Investment in Stingray Energy Services LLC	50.0%	5,718	3,800	(88)	(215)	—
Investment in Sturgeon Acquisitions LLC	25.0%	22,507	—	(1,819)	—	—
Investment in Mammoth Energy Partners LP	30.5%	143,973	—	(201)	—	—
		<u>\$ 369,581</u>	<u>\$ 440,068</u>	<u>\$ (139,434)</u>	<u>\$ (213,058)</u>	<u>\$ (8,322)</u>

The tables below summarize financial information for the Company's equity investments, excluding Diamondback, as of December 31, 2014 and 2013.

Summarized balance sheet information:

	December 31,	
	2014	2013
(In thousands)		
Current assets	\$ 181,060	\$ 84,107
Noncurrent assets	\$ 1,306,891	\$ 1,107,579
Current liabilities	\$ 114,506	\$ 112,406
Noncurrent liabilities	\$ 230,062	\$ 110,095

Summarized results of operations:

	December 31,		
	2014	2013	2012
(In thousands)			
Gross revenue	\$ 390,620	\$ 162,401	\$ 39,918
Net loss	\$ 140,796	\$ 17,350	\$ 1,943

Gross revenue and net loss presented above include approximately one month of activity for Mammoth Energy Partners LP ("Mammoth") and approximately eleven months of activity for Stingray Pressure Pumping LLC, Stingray Logistics LLC,

Muskie Proppant LLC and Bison Drilling and Field Services LLC, which were contributed to Mammoth in November 2014. See further discussion of the contribution to Mammoth below.

Tatex Thailand II, LLC

The Company has an indirect ownership interest in Tatex Thailand II, LLC ("Tatex"). Tatex holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC ("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, 2014, Gulfport received \$0.5 million in distributions from Tatex which is included in income from equity method investments in the consolidated statements of operations.

Tatex Thailand III, LLC

The Company has an ownership interest in Tatex Thailand III, LLC ("Tatex III"). Tatex III owns a concession covering approximately 245,000 acres in Southeast Asia. During the years ended December 31, 2014 and 2013, the Company paid cash calls of \$1.6 million and \$2.4 million, respectively. As of December 31, 2014, the Company reviewed its investment in Tatex III and made the decision to allow the concession to expire in 2015. As such, the Company fully impaired the asset as of December 31, 2014, recognizing a loss of \$12.1 million which is included in income from equity method investments in the accompanying consolidated statements of operations.

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings Inc. ("Grizzly Holdings"), owns an interest in Grizzly Oil Sands ULC ("Grizzly"), a Canadian unlimited liability company. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc. ("Oil Sands"). As of December 31, 2014, Grizzly had approximately 830,000 acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada. Initiation of steam injection at its first project, Algar Lake Phase 1, commenced in January 2014 and first bitumen production was achieved during the second quarter of 2014. During the years ended December 31, 2014 and 2013, Gulfport paid \$18.8 million and \$33.9 million, respectively, in cash calls. Grizzly's functional currency is the Canadian dollar. The Company's investment in Grizzly was decreased by \$16.9 million and \$12.2 million as a result of a foreign currency translation loss for the years ended December 31, 2014 and 2013, respectively, and increased by \$1.4 million as a result of a foreign currency translation gain for the year ended December 31, 2012.

Bison Drilling and Field Services LLC

During 2011, the Company invested in Bison Drilling and Field Services LLC ("Bison"). Bison owns and operates drilling rigs. During the years ended December 31, 2014 and 2013, Gulfport paid \$17.0 million and \$2.3 million, respectively, in cash calls.

The Company entered into a loan agreement with Bison effective May 15, 2012. Interest accrued at LIBOR plus 0.28% or 8%, whichever was lower, and was to be paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The loan had a maturity date of January 31, 2015. The Company loaned Bison \$1.6 million during the first nine months of 2012, all of which was repaid by Bison during the third quarter of 2012. This loan agreement was terminated in November 2014.

The Company contributed its investment in Bison to Mammoth during the fourth quarter of 2014. See below under *Mammoth Energy Partners LP* for discussion of contribution.

Muskie Proppant LLC

During 2011, the Company invested in Muskie Proppant LLC ("Muskie"). Muskie processes and sells sand for use in hydraulic fracturing by the oil and natural gas industry and holds certain rights in a lease covering land in Wisconsin for mining oil and natural gas fracture grade sand. During the years ended December 31, 2014 and 2013, Gulfport paid \$1.0 million and \$2.2 million, respectively, in cash calls to Muskie.

The Company entered into a loan agreement with Muskie effective July 1, 2013, under which it loaned Muskie \$0.9 million. Interest accrued at the prime rate plus 2.5%. The loan had a original maturity date of July 31, 2014. Effective July 31, 2014, an amendment was made to the loan agreement which changed the maturity date of the loan to July 31, 2015. During the fourth quarter of 2014, Muskie repaid the outstanding balance and the loan agreement was terminated.

The Company contributed its investment in Muskie to Mammoth during the fourth quarter of 2014. See below under *Mammoth Energy Partners LP* for discussion of contribution.

Timber Wolf Terminals LLC

During 2012, the Company invested in Timber Wolf Terminals LLC ("Timber Wolf"). The Company's initial investment during 2012 was \$1.0 million. Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. During the year ended December 31, 2014, the Company paid an immaterial amount of cash calls related to Timber Wolf. During the year ended December 31, 2013, Gulfport paid \$0.1 million in cash calls.

Windsor Midstream LLC

During 2012, the Company purchased an ownership interest in Windsor Midstream LLC ("Midstream"). Midstream owns a 28.4% interest in Coronado Midstream LLC ("Coronado"), a gas processing plant in West Texas. In February of 2015, Coronado announced its intent to sell its natural gas gathering and processing facilities for approximately \$600.0 million. During the year ended December 31, 2014, the Company paid \$2.4 million in cash calls to Midstream. During the year ended December 31, 2013, the Company paid an immaterial amount in net cash calls to Midstream.

Stingray Pressure Pumping LLC

During 2012, the Company invested in Stingray Pressure Pumping LLC ("Stingray Pressure"). Stingray Pressure provides well completion services. During the years ended December 31, 2014 and 2013, the Company paid \$2.5 million and \$1.8 million, respectively, in cash calls. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

The Company contributed its investment in Stingray Pressure to Mammoth during the fourth quarter of 2014. See below under *Mammoth Energy Partners LP* for discussion of contribution.

Stingray Cementing LLC

During 2012, the Company invested in Stingray Cementing LLC ("Stingray Cementing"). Stingray Cementing provides well cementing services. During the years ended December 31, 2014 and 2013, the Company did not pay any cash calls related to Stingray Cementing. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

Blackhawk Midstream LLC

During 2012, the Company invested in Blackhawk Midstream LLC ("Blackhawk"). Blackhawk coordinates gathering, compression, processing and marketing activities for the Company in connection with the development of its Utica Shale acreage. During the year ended December 31, 2013, the Company paid \$0.7 million in cash calls related to Blackhawk. On January 28, 2014, Blackhawk closed on the sale of its equity interests in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC for a purchase price of \$190.0 million, of which \$14.3 million was placed in escrow. Gulfport received \$84.8 million in net proceeds from this transaction in 2014, which is included in income from equity method investments in the accompanying consolidated statements of operations. Subsequent to December 31, 2014, the Company received net proceeds of approximately \$7.2 million from the release of escrow from the Blackhawk sale.

Stingray Logistics LLC

During 2012, the Company invested in Stingray Logistics LLC ("Stingray Logistics"). Stingray Logistics provides well services. During the years ended December 31, 2014 and 2013, the Company did not pay any cash calls related to Stingray Logistics.

The Company contributed its investment in Stingray Logistics to Mammoth during the fourth quarter of 2014. See below under *Mammoth Energy Partners LP* for discussion of contribution.

Diamondback Energy, Inc.

As noted above in Note 4, on October 11, 2012, following the closing of the Diamondback IPO, the Company owned 7,914,036 shares of Diamondback's outstanding common stock for an initial investment in Diamondback valued at \$138.5 million. In June and November of 2013, the Company sold 2,234,536 and 2,300,000 shares of its Diamondback common stock, respectively, and received aggregate net proceeds of approximately \$192.7 million. In June and September of 2014, the Company sold 1,000,000 and 1,437,500 shares of its Diamondback common stock, respectively, and received aggregate net proceeds of approximately \$197.6 million. On November 12, 2014, the Company sold its remaining 942,000 shares of Diamondback common stock for net proceeds of approximately \$60.8 million. As of December 31, 2014, the Company did not own any shares of Diamondback common stock.

The Company accounted for its interest in Diamondback as an equity method investment and had elected the fair value option of accounting for this investment. While the investment in Diamondback was below 20% ownership prior to November 2014, the Company had appointed a member of Diamondback's Board as discussed in Note 4. The individual appointed by the Company continues to serve on Diamondback's board and the Company had influence through this board seat. The Company recognized an aggregate gain of approximately \$79.7 million, \$220.1 million and \$12.8 million on its investment in Diamondback for years ended December 31, 2014, 2013, and 2012, respectively, which is included in income from equity method investments in the consolidated statements of operations.

The Company has determined that for the periods presented in its consolidated financial statements, Diamondback has met the conditions of a significant subsidiary under Rule 1-02(w) of Regulation S-X, for which the Company is required, pursuant to Rule 3-09 of Regulation S-X, to attach separate financial statements as exhibits to its Annual Report on Form 10-K.

Stingray Energy Services LLC

During 2013, the Company invested in Stingray Energy Services LLC ("Stingray Energy"). Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. During the year ended December 31, 2014, the Company did not pay any cash calls to Stingray Energy. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

Sturgeon Acquisitions LLC

During the third quarter of 2014, the Company invested \$20.7 million and received an ownership interest of 25% in Sturgeon Acquisitions LLC ("Sturgeon"). Sturgeon owns and operates sand mines that produce hydraulic fracturing grade sand.

Mammoth Energy Partners LP

In the fourth quarter of 2014, the Company contributed its investments in Stingray Pressure, Stingray Logistics, Bison and Muskie to Mammoth for a 30.5% interest in this newly formed limited partnership. Mammoth has filed a registration statement on Form S-1 with the SEC in connection with its proposed initial public offering. Mammoth intends to pursue this offering in 2015 subject to market conditions.

The Company accounted for the contribution as a sale of financial assets under ASC 860. The Company estimated the fair market value of its investment in Mammoth as of the contribution date using an average of the market approach and the income approach, based on a independently prepared valuation of the contributed assets. The fair market value was reduced by a discount factor for lack of marketability due to the Company's minority interest, resulting in a fair value of \$143.5 million for the Company's 30.5% interest. The fair value of the assets and liabilities acquired was estimated using assumptions that represent Level 3 inputs. See "Note 14 - Fair Value Measurements" for additional discussion of the measurement inputs. The Company recognized a gain of \$84.5 million from its contribution of assets to Mammoth, which is included in gain on contribution of investments in the accompanying consolidated statements of operations.

6. OTHER ASSETS

Other assets consist of the following as of December 31, 2014 and 2013:

	December 31,	
	2014	2013
	(In thousands)	
Plugging and abandonment escrow account on the WCBB properties (Note 16)	\$ 3,097	\$ 3,105
Certificates of Deposit securing letter of credit	275	275
Prepaid drilling costs	483	526
Loan commitment fees	15,390	9,341
Derivative receivable	—	4,493
Deposits	34	34
Other	117	77
	<u>\$ 19,396</u>	<u>\$ 17,851</u>

7. LONG-TERM DEBT

Long-term debt consisted of the following items as of December 31, 2014 and 2013:

	December 31,	
	2014	2013
	(In thousands)	
Revolving credit agreement (1)	\$ 100,000	\$ —
Building loans (2)	1,826	1,995
7.75% senior unsecured notes due 2020 (3)	600,000	300,000
Unamortized original issue premium (discount), net (4)	14,658	(2,808)
Less: current maturities of long term debt	(168)	(159)
Debt reflected as long term	<u>\$ 716,316</u>	<u>\$ 299,028</u>

Maturities of long-term debt (excluding premiums and discounts) as of December 31, 2014 are as follows:

	(In thousands)
2015	\$ 168
2016	1,658
2017	—
2018	100,000
2019	—
Thereafter	600,000
Total	<u>\$ 701,826</u>

The Company capitalized approximately \$9.7 million and \$7.1 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2014 and 2013, respectively.

(1) On September 30, 2010, the Company entered into a senior secured revolving credit agreement with the Bank of Nova Scotia as the lead arranger and administrative agent and certain lenders from time to time party thereto. On December 27, 2013, the Company amended and restated its credit agreement in its entirety (the "Amended and Restated Credit Agreement"). The Amended and Restated Credit Agreement provided for an increase in the maximum facility amount from \$350.0 million to \$1.5 billion, with an increase in borrowing base availability as of December 27, 2013 from \$50.0 million to \$150.0 million. The credit agreement is secured by substantially all of the Company's assets. The Amended and Restated Credit Agreement matures on June 6, 2018.

On April 23, 2014, the Company entered into a first amendment to the Amended and Restated Credit Agreement. The first amendment increased the letter of credit sublimit from \$20.0 million to \$70.0 million and provided for an increase in the

borrowing base availability from \$150.0 million to \$275.0 million. The first amendment also made certain changes to the lenders and their respective lending commitments thereunder.

On November 26, 2014, the Company entered into a second amendment to the Amended and Restated Credit Agreement. The second amendment changed the definition of EBITDAX to exclude proceeds from the disposition of equity method investments and changed the ratio of funded debt to EBITDAX to be the ratio of net funded debt to EBITDAX. Net funded debt is funded debt less the amount of cash and short-term investments the Company has at the end of the relevant fiscal quarter. The second amendment increases the ratio from 2.00 to 1.00 to 3.50 to 1.00 for the period December 31, 2014 through June 30, 2015 and then decreases the ratio to 3.25 to 1.00 for the periods thereafter. Further, the second amendment increased the letter of credit sublimit from \$70.0 million to \$125.0 million and provided for an increase in the borrowing base availability from \$275.0 million to \$450.0 million. As of December 31, 2014, \$100.0 million was outstanding under the Amended and Restated Credit Agreement. At December 31, 2014, the total availability for future borrowings under Amended and Restated Credit Agreement, after giving effect to an aggregate of \$43.6 million of letters of credit, was \$306.4 million. The Company's wholly-owned subsidiaries have guaranteed the obligations of the Company under the Amended and Restated Credit Agreement.

Advances under the Amended and Restated Credit Agreement 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 0.50% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (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 1.50% to 2.50%, plus (2) the London interbank offered rate that appears on pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or service that displays on average London interbank offered rate as determined by ICE Benchmark Administration (or any other person that takes over administration of such 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. At December 31, 2014, amounts borrowed under the Amended and Restated Credit Agreement bore interest at the Eurodollar rate (1.91%).

The Amended and Restated Credit Agreement contains customary negative covenants including, but not limited to, restrictions on the Company's and its 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 affiliates.

The negative covenants are subject to certain exceptions as specified in the Amended and Restated Credit Agreement. The Amended and Restated Credit Agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants:

(i) the ratio of net funded debt to EBITDAX (net income, excluding (i) any non-cash revenue or expense associated with swap contracts resulting from ASC 815 and (ii) any cash or noncash revenue or expense attributable to minority investments plus without duplication and, in the case of expenses, 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) exploration costs deducted in determining net income under successful efforts accounting, (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 (provided that expenses related to any unsuccessful disposition will be limited to \$3.0 million in the aggregate) for a twelve-month period may not be greater than 3.50 to 1.00 for the period December 31, 2014 through June 30, 2015 and 3.25 to 1.00 for the twelve-month period ending September 30, 2015 and periods thereafter; and

(ii) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00.

The Company was in compliance with all covenants at December 31, 2014.

The Bank of Nova Scotia, as sole lead arranger and administrative agent of the Company's revolving credit facility, as part of the regular spring 2015 borrowing base redetermination process, informed the Company that it will be recommending to the lending syndicate an increase in the Company's borrowing base under this facility from \$450.0 million to \$575.0 million. The Company expects final approval and implementation of the borrowing base increase to be completed within the next 30 to 45 days by the lending syndicate.

(2) In March 2011, the Company entered into a new building loan agreement for the office building it occupies in Oklahoma City, Oklahoma. The new loan agreement refinanced the \$2.4 million outstanding under the previous building loan agreement. The new agreement matures in February 2016 and bears interest at the 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.

(3) On October 17, 2012, the Company issued \$250.0 million in aggregate principal amount of 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, (the "October Notes Offering") under an indenture among the Company, its subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee, (the "senior note indenture"). On December 21, 2012, the Company issued an additional \$50.0 million in aggregate principal amount of 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 Offering"). The December Notes were issued as additional securities under the senior note indenture. The October Notes Offering and the December Notes Offering are collectively referred to as the "Notes Offerings". The Company used a portion of the net proceeds from the October Notes Offering to repay all amounts outstanding at such time under its revolving credit facility. The Company used the remaining net proceeds of October Notes Offering and the net proceeds of the December Notes Offering for general corporate purposes, which included funding a portion of its 2013 capital development plan. The October Notes and the December Notes were exchanged for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act in October 2013 (the "Exchange Notes").

On August 18, 2014, the Company issued an additional \$300.0 million in aggregate principal amount of senior unsecured notes due 2020 (the "August 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 August Notes Offering"). The August Notes were issued as additional securities under the senior note indenture. The Company used a portion of the net proceeds from the August Notes Offering to repay all amounts outstanding at such time under its revolving credit facility. The Company used the remaining net proceeds of the August Notes Offering for general corporate purposes, including funding a portion of its 2014 capital development plans. The October Notes Offering, December Notes Offering and the August Notes Offering are collectively referred to as the "Notes Offerings" and the Exchange Notes, and the August Notes are collectively referred to as the "Notes".

In connection with the issuance of the August Notes, the Company and the subsidiary guarantors entered into a registration rights agreement with the initial purchasers on August 18, 2014, pursuant to which the Company and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the August Notes for a new issue of substantially identical debt securities registered under the Securities Act. The registration statement relating to the exchange offer for the August Notes was filed on November 6, 2014, as amended on February 3, 2015, and declared effective by the SEC on February 4, 2015. The exchange offer for the August Note is expected to be completed on or about March 10, 2015.

Under the senior note indenture, interest on the Notes accrues at a rate of 7.75% 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 the Company's senior unsecured obligations and rank equally in the right of payment with all of the Company's other senior indebtedness and senior in right of payment to any future subordinated indebtedness. All of the Company's existing and future restricted subsidiaries that guarantee the Company's 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 the Company's future unrestricted subsidiaries. The Company 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, the Company 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, the Company 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.

(4) The October Notes were issued at a price of 98.534% resulting in a gross discount of \$3.7 million and an effective rate of 8.000%. The December Notes were issued at a price of 101.000% resulting in a gross premium of \$0.5 million and an effective rate of 7.531%. The August Notes were issued at a price of 106.000% resulting in a gross premium of \$18.0 million and an effective rate of 6.561%. The premium and discount are being amortized using the effective interest method.

Interest Expense

The following schedule shows the components of interest expense at December 31, 2014, 2013 and 2012:

	December 31,		
	2014	2013	2012
	(In thousands)		
Cash paid for interest	\$ 28,646	\$ 24,270	\$ 1,404
Change in accrued interest	3,875	(969)	4,155
Write-off of deferred loan costs	—	—	1,143
Capitalized interest	(9,687)	(7,132)	—
Amortization of loan costs	1,685	1,012	640
Amortization of note discount and premium	(533)	298	59
Other	—	11	57
Total interest expense	<u>\$ 23,986</u>	<u>\$ 17,490</u>	<u>\$ 7,458</u>

8. COMMON STOCK OPTIONS, WARRANTS, RESTRICTED STOCK AND CHANGES IN CAPITALIZATION

Options

In January 2005, the Company adopted the 2005 Stock Incentive Plan ("2005 Plan"), which is administered by the Compensation Committee (the "Committee"). Under the terms of the 2005 Plan, the Committee may determine when options shall be granted, to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting periods of such options and the exercisable period of such options. Eligible participants are defined as employees, consultants, and directors of the Company.

On April 20, 2006, the Company amended and restated the 2005 Plan to (i) include (a) incentive stock options, (b) nonstatutory stock options, (c) restricted awards (restricted stock and restricted stock units), (d) performance awards and (e) stock appreciation rights and (ii) increase the maximum aggregate amount of common stock that may be issued under the 2005 Plan from 1,904,606 shares to 3,000,000 shares, including the 627,337 shares underlying options granted to employees under the Plan prior to adoption of the 2005 Plan. As of December 31, 2014, the Company had granted 997,269 options for the purchase of shares of the Company's common stock and 1,143,217 shares of restricted stock under the 2005 Plan. No additional securities will be issued under the Plan other than upon exercise of options that are outstanding.

On April 19, 2013, the Company amended and restated the 2005 Plan with the 2013 Restated Stock Incentive Plan ("2013 Plan"). The 2013 Plan increased the numbers of shares that may be awarded from 3,000,000 to 7,500,000 shares, including the

627,337 shares underlying options granted to employees under the Plan. The shares of stock issued once the options are exercised will be from authorized but unissued common stock. As of December 31, 2014, the Company had granted 258,361 shares of restricted stock under the 2013 Plan.

Sale of Common Stock

On December 24, 2012, the Company completed the sale of an aggregate of 11,750,000 shares of its common stock in an underwritten public offering (including the partial exercise of a 1,650,000 share over-allotment option granted to the underwriters, which option was initially exercised to the extent of 750,000 shares) at a public offering price of \$38.00 per share less the underwriting discount. The underwriters subsequently exercised their option to purchase the remaining 900,000 additional shares of common stock subject to the over-allotment option in a second closing, which occurred on January 7, 2013. The Company received aggregate net proceeds from both closings of approximately \$460.7 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used a portion of these net proceeds to fund the acquisition of approximately 37,000 net acres in the Utica Shale, as described above in Note 2, and for general corporate purposes, including the funding of a portion of its 2013 capital development plan.

On February 15, 2013, the Company completed the sale of an aggregate of 8,912,500 shares of its common stock in an underwritten public offering at a public offering price of \$38.00 per share less the underwriting discount. The Company received aggregate net proceeds of approximately \$325.8 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used a portion of the net proceeds from this equity offering to fund its acquisition of additional Utica Shale acreage as described in Note 2, and the balance for general corporate purposes, including the funding of a portion of its 2013 capital development plan.

On November 13, 2013, the Company completed the sale of an aggregate of 7,475,000 shares of its common stock in an underwritten public offering at a public offering price of \$56.75 per share less the underwriting discount. The Company received aggregate net proceeds of approximately \$408.0 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company has used and intends to continue to use the net proceeds from this equity offering for general corporate purposes, which may include expenditures associated with its 2014 drilling program and additional acreage acquisitions in the Utica Shale.

Private Placement Offering

In March 2002, the Company completed a private placement offering of 10,000 units. Each unit consisted of (i) one share of Cumulative Preferred Stock, Series A, of the Company (the "Preferred") and (ii) a warrant to purchase up to 250 shares of common stock, par value \$0.01 per share, of the Company (the "Warrants"). Holders of the Preferred were entitled to receive dividends at the rate of 12% of the liquidation preference per annum payable quarterly in cash or, at the option of the Company for all quarters ending on or prior to March 31, 2004, payable in whole or in part in additional shares of Preferred at the rate of 15% of the liquidation preference per annum. All Preferred shares were redeemed in 2005.

The 2,322,962 Warrants issued had a term of 10 years and a current exercise price of \$1.19 per share of common stock subject to adjustment. The Company granted to holders of the Warrants certain demand and piggyback registration rights with respect to shares of common stock issuable upon exercise of the Warrants. The 8,875 unexercised warrants expired on March 31, 2012.

9. STOCK-BASED COMPENSATION

During the years ended December 31, 2014, 2013 and 2012 the Company's stock-based compensation cost was \$14.9 million, \$10.5 million and \$4.7 million, respectively, of which the Company capitalized \$5.9 million, \$4.2 million and \$1.9 million, respectively, relating to its exploration and development efforts.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model. Expected volatilities are based on the historical volatility of the market price of Gulfport's common stock over a period of time ending on the grant date. Based upon the historical experience of the Company, the expected term of options granted is equal to the vesting period plus one year. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of the grant. The 2013 Restated Stock Incentive Plan (which amended and restated the 2005 Plan) provides that all options must have an exercise price not less than the fair value of the Company's common stock on the date of the grant.

No stock options were issued during the years ended December 31, 2014, 2013 and 2012.

The Company has not declared dividends and does not intend to do so in the foreseeable future, and thus did not use a dividend yield. In each case, the actual value that will be realized, if any, depends on the future performance of the common stock and overall stock market conditions. There is no assurance that the value an optionee actually realizes will be at or near the value estimated using the Black-Scholes model.

A summary of the status of stock options and related activity for the years ended December 31, 2014, 2013 and 2012 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Options outstanding at December 31, 2011	356,241	\$ 6.51	3.41	\$ 8,172
Granted	—	—		
Exercised	(21,000)	8.80		628
Forfeited/expired	—	—		
Options outstanding at December 31, 2012	335,241	6.37	2.39	\$ 10,678
Granted	—	—		
Exercised	(125,000)	11.20		4,797
Forfeited/expired	—	—		
Options outstanding at December 31, 2013	210,241	3.50	1.07	\$ 12,538
Granted	—	—		
Exercised	(205,241)	3.36		12,822
Forfeited/expired	—	—		
Options outstanding at December 31, 2014	5,000	\$ 9.07	0.69	\$ 163
Options exercisable at December 31, 2014	5,000	\$ 9.07	0.69	\$ 163

The following table summarizes information about the stock options outstanding at December 31, 2014:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
\$ 9.07	5,000	0.69	5,000
	5,000		5,000

The following table summarizes restricted stock activity for the twelve months ended December 31, 2014, 2013 and 2012:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2011	203,348	\$ 26.02
Granted	196,832	35.87
Vested	(135,015)	29.59
Forfeited	(19,334)	26.81
Unvested shares as of December 31, 2012	245,831	\$ 31.88
Granted	463,952	\$ 50.00
Vested	(237,646)	41.79
Forfeited	(8,500)	38.54
Unvested shares as of December 31, 2013	463,637	\$ 44.80
Granted	246,409	\$ 65.07
Vested	(272,665)	45.76
Forfeited	(50,136)	53.72
Unvested shares as of December 31, 2014	387,245	\$ 55.87

Unrecognized compensation expense as of December 31, 2014 related to outstanding stock options and restricted shares was \$17.9 million. The expense is expected to be recognized over a weighted average period of 1.49 years.

10. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current debt are carried at cost, which approximates market value due to their short-term nature. Long-term debt related to the building loan is carried at cost, which approximates market value based on the borrowing rates currently available to the Company with similar terms and maturities.

At December 31, 2014, the carrying value of the outstanding debt represented by the Notes was \$614.7 million, including the remaining unamortized discount of approximately \$2.8 million related to the October Notes and the remaining unamortized premium of approximately \$0.4 million related to the December Notes and \$17.1 million related to the August Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately \$587.6 million at December 31, 2014.

The fair value of the derivative instruments is computed based on the difference between the prices provided by the fixed-price contracts and forward market prices as of the specified date, as adjusted for basis differentials. Forward market prices for oil and natural gas are dependent upon supply and demand factors in such forward market and are subject to significant volatility.

11. INCOME TAXES

The income tax provision for continuing operations consists of the following:

	2014	2013	2012
	(In thousands)		
Current:			
State	\$ 14,384	\$ 6,860	\$ 84
Federal	16,039	6,325	646
Deferred:			
State	4,314	7,385	2,214
Federal	118,604	77,566	23,419
Total income tax expense provision from continuing operations	<u>\$ 153,341</u>	<u>\$ 98,136</u>	<u>\$ 26,363</u>

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

	2014	2013	2012
	(In thousands)		
Income from continuing operations before federal income taxes	<u>\$ 400,744</u>	<u>\$ 251,328</u>	<u>\$ 98,199</u>
Expected income tax at statutory rate	140,259	87,965	34,370
State income taxes	11,570	9,297	1,493
Other differences	1,512	874	292
Changes in valuation allowance	—	—	(9,792)
Income tax expense recorded for continuing operations	<u>\$ 153,341</u>	<u>\$ 98,136</u>	<u>\$ 26,363</u>

The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2014, 2013 and 2012 are estimated as follows:

	2014	2013	2012
	(In thousands)		
Deferred tax assets:			
Net operating loss carryforward	\$ 1,091	\$ 1,462	\$ 1,513
FASB ASC 718 compensation expense	1,562	634	762
AMT credit	24,053	7,968	1,643
Charitable contributions carryover	150	25	5
Unrealized loss on hedging activities	—	8,540	3,836
Foreign tax credit carryforwards	2,074	2,074	2,074
Accrued liabilities	1,260	—	—
State net operating loss carryover	2,627	4,408	4,315
Total deferred tax assets	32,817	25,111	14,148
Valuation allowance for deferred tax assets	(3,145)	(4,743)	(4,629)
Deferred tax assets, net of valuation allowance	29,672	20,368	9,519
Deferred tax liabilities:			
Oil and gas property basis difference	183,767	72,173	15,049
Investment in pass through entities	38,315	8,799	3,618
Non-oil and gas property basis difference	849	249	227
Investment in nonconsolidated affiliates	—	46,495	9,232
Unrealized gain on hedging activities	37,006	—	—
Total deferred tax liabilities	259,937	127,716	28,126
Net deferred tax liability	\$ (230,265)	\$ (107,348)	\$ (18,607)

The Company has an available federal tax net operating loss carryforward estimated at approximately \$3.1 million as of December 31, 2014. This carryforward will begin to expire in the year 2034. Based upon the December 31, 2014, 2013 and 2012 net deferred tax liability position of the Company's oil and gas assets, management believes that this is a positive source of evidence to utilize the carryforward before it expires. Therefore, a valuation allowance has not been provided at December 31, 2014, 2013 and 2012. The Company also has state net operating loss carryovers of \$50.5 million from Louisiana that will begin to expire in 2014, alternative minimum tax credits of \$24.1 million with no expiration date and federal foreign tax credit carryovers of \$2.1 million which begin to expire in 2017. The Company has recorded a valuation allowance of \$3.1 million related to state net operating loss carryovers and foreign tax credit carryovers as the carryovers may not be utilized based upon a more likely than not basis.

In 2012, the Diamondback Contribution generated an estimated \$61.9 million taxable gain. As a result, the Company recognized \$9.8 million of its deferred tax assets which had previously been subject to a valuation allowance. The Company also recognized \$25.6 million of deferred tax expense in 2012 primarily due to the utilization of prior net operating losses from the Diamondback Contribution gain. In 2013, the sale of Diamondback common shares generated \$120.0 million taxable gain resulting in deferred tax expense of \$35.7 million and current tax expense of \$13.2 million. In 2014, the sale of the remaining shares of Diamondback, as well as the sale of Blackhawk, generated \$203.3 million and \$83.7 million taxable gains, respectively, resulting in a deferred tax expense of \$79.4 million and \$32.3 million, respectively. The Company's current federal tax expense in 2014, 2013 and 2012 is primarily attributable to alternative minimum tax, primarily generated by taxable gains from the sale of shares of Diamondback and the sale of assets by Blackhawk in 2014.

At December 31, 2014 and 2013, the Company owed approximately \$17.7 million and \$11.0 million, respectively, for state and federal income taxes payable which is included on the accompanying consolidated balance sheets.

12. EARNINGS PER SHARE

Reconciliations of the components of basic and diluted net income per common share are presented in the tables below:

	For the Year Ended December 31,								
	2014			2013			2012		
	Income	Shares	Per Share	Income	Shares	Per Share	Income	Shares	Per Share
(In thousands, except share data)									
Basic:									
Net income	\$247,403	85,445,963	\$ 2.90	\$153,192	77,375,683	\$ 1.98	\$68,371	55,933,354	\$ 1.22
Effect of dilutive securities:									
Stock options and awards	—	367,219		—	485,963		—	484,134	
Diluted:									
Net income	\$247,403	85,813,182	\$ 2.88	\$153,192	77,861,646	\$ 1.97	\$68,371	56,417,488	\$ 1.21

There were no potential shares of common stock that were considered anti-dilutive for the years ended December 31, 2014, 2013 and 2012.

13. HEDGING ACTIVITIES

Oil Price Hedging Activities

The Company seeks to reduce its exposure to unfavorable changes in oil and natural gas prices, which are subject to significant and often volatile fluctuation, by entering into fixed price swaps. These contracts allow the Company to predict with greater certainty the effective oil and natural gas prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production.

The Company accounts for its oil and natural gas derivative instruments as cash flow hedges for accounting purposes under FASB ASC 815 and related pronouncements. All derivative contracts are marked to market each quarter end and are included in the accompanying consolidated balance sheets as derivative assets and liabilities.

During 2013 and 2014, the Company entered into fixed price swap and swaption contracts for 2013 through 2017 with four financial institutions. The Company's fixed price swap contracts are tied to the commodity prices on the International Petroleum Exchange ("IPE") and NYMEX. The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price as listed on the IPE for Brent Crude and the NYMEX WTI for oil and on the NYMEX Henry Hub for natural gas. At December 31, 2014, the Company had the following fixed price swaps in place:

	Daily Volume (MMBtu/day)	Weighted Average Price
January 2015 - March 2015	190,625	\$ 4.12
April 2015	191,250	\$ 4.05
May 2015 - June 2015	201,250	\$ 4.05
July 2015 - September 2015	216,875	\$ 4.04
October 2015 - December 2015	232,500	\$ 4.04
January 2016 - March 2016	172,500	\$ 3.99
April 2016	162,500	\$ 3.99
May 2016 - December 2016	92,500	\$ 3.97
January 2017 - June 2017	62,500	\$ 3.96

At December 31, 2014 the fair value of derivative assets and liabilities related to the fixed price swaps was as follows:

	(In thousands)
Short-term derivative instruments - asset	\$ 78,391
Long-term derivative instruments - asset	\$ 24,448

At December 31, 2013 the fair value of derivative assets and liabilities related to the fixed price swaps and swaptions was as follows:

	(In thousands)
Short-term derivative instruments - asset	\$ 324
Long-term derivative instruments - asset	\$ 521
Short-term derivative instruments - liability	\$ 12,280
Long-term derivative instruments - liability	\$ 11,366

All fixed price swaps have been executed in connection with the Company's oil and natural gas price hedging program. For fixed price swaps qualifying as cash flow hedges pursuant to FASB ASC 815, the realized contract price is included in oil and gas sales in the period for which the underlying production was hedged.

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 (loss) until the hedged item is recognized in earnings. Amounts reclassified out of accumulated other comprehensive income (loss) into earnings as a component of oil and condensate sales for the years ended December 31, 2014, 2013 and 2012 are presented below.

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Reduction to oil and condensate sales	\$ —	\$ (9,779)	\$ (1,517)

At December 31, 2014, no amounts related to fixed price swaps remain in accumulated other comprehensive income (loss).

The following table presents the balances of the Company's cumulative hedging activities included in other comprehensive loss.

	(In thousands)	
December 31, 2011	\$	1,576
December 31, 2012	\$	(9,660)
December 31, 2013	\$	—
December 31, 2014	\$	—

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. The Company recognized a gain of \$121.1 million related to hedge ineffectiveness for the year ended December 31, 2014, which is included in oil and condensate and gas sales in the consolidated statements of operations. The Company recognized a loss of \$18.2 million related to hedge ineffectiveness for the year ended December 31, 2013, which is included in oil and condensate and gas sales in the consolidated statements of operations. This loss was comprised of a loss of \$9.1 million related to hedge ineffectiveness and a loss of \$9.1 million related to the amortization of other comprehensive income for the year ended December 31, 2013. The Company recognized a loss of \$0.1 million related to hedge ineffectiveness for the year ended December 31, 2012, which is included in oil and condensate sales in the consolidated statements of operations.

The Company delivered approximately 62% of its 2014 production under fixed price swaps.

14. FAIR VALUE MEASUREMENTS

The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value in accordance with FASB ASC 820. FASB ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1 – Quoted prices in active markets for identical assets and liabilities.

Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 – Significant inputs to the valuation model are unobservable.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

The following tables summarize the Company's financial and non-financial liabilities by FASB ASC 820 valuation level as of December 31, 2014 and 2013:

	December 31, 2014			
	Level 1	Level 2	Level 3	
	(In thousands)			
Assets:				
Fixed price swaps	\$ —	\$ 102,839	\$ —	\$ —
December 31, 2013				
	Level 1	Level 2	Level 3	
	(In thousands)			
	Assets:			
Fixed price swaps	\$ —	\$ 845	\$ —	\$ —
Equity investment in Diamondback	178,708	—	—	—
Liabilities:				
Fixed price swaps	\$ —	\$ 23,646	\$ —	\$ —

The estimated fair value of the Company's fixed price swap contracts were based upon forward commodity prices based on quoted market prices, adjusted for differentials. See Note 13 for further discussion of the Company's hedging activities. The estimated fair value of the Company's equity investment in Diamondback was based upon the public closing share price of Diamondback's common stock as of December 31, 2013.

The estimated fair values of proved oil and gas properties assumed in business combinations are based on a discounted cash flow model and market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk-adjusted discount rates. The estimated fair values of unevaluated oil and gas properties was based on geological studies, historical well performance, location and applicable mineral lease terms. Based on the unobservable nature of certain of the inputs, the estimated fair value of the oil and gas properties assumed is deemed to use Level 3 inputs. See Note 2 for further discussion of the Company's acquisitions.

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, "Asset Retirement and Environmental Obligations" ("FASB ASC 410"). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 4 for further discussion of the Company's asset retirement obligations. Asset retirement obligations incurred during the year ended December 31, 2014 were approximately \$9.3 million.

Due to the unobservable nature of the inputs, the fair value of the Company's initial investment in Mammoth was estimated using assumptions that represent level 3 inputs. The Company estimated the fair value of the investment as of the November 24, 2014 contribution date. See Note 5 for further discussion of the Company's contribution to Mammoth. The estimated fair value of the Company's investment in Mammoth was \$143.5 million at December 31, 2014.

15. RELATED PARTY TRANSACTIONS

In the ordinary course of business, the Company has conducted business activities with certain related parties.

Gulfport is the operator of its Niobrara Formation acreage under a development agreement with Windsor Niobrara LLC ("Windsor Niobrara"). As operator, the Company is responsible for daily operations, monthly operation billings and monthly revenue disbursements for these properties. For the year ended December 31, 2013, the Company billed Windsor Niobrara approximately \$0.9 million for these services. At December 31, 2013, Windsor Niobrara owed the Company an immaterial amount for these services. Windsor Niobrara was not a related party in 2014.

Windsor Ohio LLC ("Windsor Ohio") participated with the Company in the acquisition of certain leasehold interests in acreage located in the Utica Shale in Ohio. As operator of this acreage, the Company is responsible for daily operations, monthly operation billings and monthly revenue disbursements for these properties. For the year ended December 31, 2013, the Company billed Windsor Ohio approximately \$73.4 million for these services. At December 31, 2013, Windsor Ohio owed the

Company approximately \$1.6 million for these services. During the years ended December 31, 2013 and 2012, the Company purchased certain oil and natural gas properties in the Utica Shale from Windsor Ohio. For information regarding these transactions, see Note 2. Windsor Ohio was not a related party in 2014.

Stingray Pressure provides well completion services. Stingray Pressure was previously 50% owned by the Company until its contribution to Mammoth in November 2014 as discussed above in Note 5. As of the contribution date, the Company owns a 30.5% limited partner interest in Mammoth. No amounts were owed to Stingray Pressure at the date of the contribution. As of December 31, 2013, the Company owed Stingray Pressure approximately \$8.3 million related to these services. Approximately \$78.3 million and \$58.3 million of services provided by Stingray Pressure are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2014 and 2013, respectively.

Stingray Cementing, which is 50% owned by the Company, provides well cementing services as discussed above in Note 5. At December 31, 2014 and 2013, the Company owed Stingray Cementing approximately \$0.8 million and \$1.5 million, respectively, related to these services. Approximately \$6.0 million and \$4.0 million of services provided by Stingray Cementing are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2014 and 2013, respectively.

Stingray Energy, which is 50% owned by the Company, provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites as discussed above in Note 5. At December 31, 2014 and 2013, the Company owed Stingray Energy approximately \$6.0 million and \$4.1 million, respectively, related to these services. Approximately \$1.3 million and an immaterial amount of services provided by Stingray Energy are included in lease operating expenses in the consolidated statements of operations for the year ended December 31, 2014 and 2013, respectively. Approximately \$24.8 million and \$5.1 million of services provided by Stingray Energy are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2014 and 2013, respectively.

Athena Construction LLC ("Athena") performs services for the Company at its WCBB and Hackberry fields. At December 31, 2013, the Company owed Athena approximately \$1.0 million related to these services. Approximately \$0.6 million of services provided by Athena are included in lease operating expenses in the consolidated statements of operations for the year ended December 31, 2013. Approximately \$4.1 million related to services performed by Athena are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2013. Athena was not a related party in 2014.

Black Fin P&A, LLC ("Black Fin") performed plugging and abandonment services for the Company at its WCBB field. No amounts were owed to Black Fin at December 31, 2013. An immaterial amount of services performed by Black Fin are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2013. Black Fin was not a related party in 2014.

Panther Drilling Systems, LLC ("Panther") performs directional drilling services for the Company. In November 2014, Panther became a wholly-owned subsidiary of Mammoth. The Company owns a 30.5% limited partner interest in Mammoth as discussed above in Note 5. At December 31, 2014 and 2013, the Company owed Panther approximately \$2.4 million and \$1.8 million, respectively, related to these services. Approximately \$7.6 million and \$12.6 million of services provided by Panther are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2014 and 2013, respectively.

Redback Directional Services, LLC ("Redback") provides coil tubing and flow back services for the Company. In November 2014, Redback became a wholly-owned subsidiary of Mammoth. The Company owns a 30.5% limited partner interest in Mammoth as discussed above in Note 5. At December 31, 2014, the Company owed Redback approximately \$0.4 million related to these services. No amounts were owed to Redback at December 31, 2013. Approximately \$1.0 million and \$0.1 million related to services performed by Redback are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2014 and 2013, respectively.

In November 2014, the Company contributed its investment in Muskie, Stingray Pressure, Stingray Logistics and Bison to Mammoth, of which the Company owns 30.5%. Approximately \$11.1 million of services provided by Mammoth are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2014. At December 31, 2014, the Company owed Mammoth approximately \$28.4 million related to these services.

Caliber Development Company, LLC ("Caliber") provides building maintenance services for the Company's headquarters in Oklahoma City, Oklahoma. Caliber also leases office space to the Company. At December 31, 2013, the Company owed Caliber an immaterial amount related to these services. Approximately \$0.2 million of services performed by Caliber and rent paid to Caliber are included in general and administrative expenses on the accompanying consolidated statements of operations for the year ended December 31, 2013. Caliber was not a related party in 2014.

Each of Diamondback, Windsor Niobrara, Windsor Ohio, Stingray Pressure, Stingray Cementing, Stingray Energy, Stingray Logistics, Athena, Black Fin, Panther, Redback and Caliber is affiliated with or controlled by Wexford Capital LP ("Wexford"). In addition, affiliates of Wexford own the general partner of Mammoth and the remaining 69.5% limited partner interest in Mammoth. See Note 5 above. Prior to September 21, 2012, Wexford and/or its affiliates beneficially owned more than 10% of the Company's common stock and was deemed to be a related party. On or about September 28, 2012, Wexford's and/or its affiliates' ownership of Gulfport's common stock dropped to below 1% and, as a result, was no longer deemed to be a related party. Subsequent to September 28, 2012, the Company continued to treat Windsor Niobrara, Windsor Ohio, Athena, Black Fin, Panther, Redback and Caliber as related parties because Mr. Mike Liddell, the Company's former Chairman of the Board and a named executive officer during 2013, had informed the Company that he was the operating member of each such entity and also held a 10% participation interest in Windsor Ohio and a 10% contingent participation interest in Windsor Niobrara, Athena, Black Fin, Panther, Redback and Caliber. Mr. Liddell is no longer a related party with respect to the Company.

16. COMMITMENTS

Plugging and Abandonment Funds

In connection with the Company's acquisition in 1997 of the remaining 50% interest in its WCBB properties, the Company 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, the Company could access the trust for use in plugging and abandonment charges associated with the property, although it has not yet done so. As of December 31, 2014, the plugging and abandonment trust totaled approximately \$3.1 million. At December 31, 2014, the Company had plugged 450 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) and Profit Sharing plan under which eligible employees may contribute up to 100% of their total compensation up to the maximum pre-tax threshold through salary deferrals. Also under the plan, the Company will make a contribution each calendar year on behalf of each employee equal to at least 3% of his or her salary, regardless of the employee's participation in salary deferrals and may also make additional discretionary contributions. During the years ended December 31, 2014, 2013 and 2012, Gulfport incurred \$0.8 million, \$0.6 million, and \$0.4 million, respectively, in contributions expense related to this plan.

Employment Agreements

Effective November 1, 2012, the Company entered into employment agreements with Mike Liddell, the Company's former Chairman, James D. Palm, the Company's former Chief Executive Officer, and Michael G. Moore, the Company's former Chief Financial Officer. Each agreement had an initial three-year term expiring on November 1, 2015 subject to automatic one-year extensions unless terminated by either party to the agreement at least 90 days prior to the end of the then current term. These agreements provided for minimum salary and bonus levels which were subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's Amended and Restated 2005 Stock Incentive Plan (or other equity incentive plans that may be put in place for the benefit of employees) and other employee benefits.

Effective February 15, 2014, Mr. Palm retired and his employment agreement with the Company terminated. The Company entered into a separation agreement with Mr. Palm, under which agreement certain benefits are provided to, and obligations imposed on, Mr. Palm. As of December 31, 2014, the minimum commitment under Mr. Palm's separation agreement was approximately \$0.6 million.

Mr. Liddell resigned as the Company's Chairman effective June 2013 at which date his employment agreement with Gulfport terminated. At that same time, the Company entered into a consulting agreement with Mr. Liddell. In October 2014, Mr. Liddell terminated his consulting agreement with the Company effective January 1, 2015.

On April 22, 2014, the Board of Directors appointed Michael G. Moore as Chief Executive Officer of the Company. The Company and Mr. Moore entered into an amended and restated employment agreement. The agreement has a three-year term commencing effective April 22, 2014. This agreement provides, among other things, for a minimum salary level, subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits. The aggregate minimum commitment for future salary at December 31, 2014 under the April 22, 2014 amended and restated employment agreement was approximately \$0.9 million.

Firm Transportation Commitments

As of December 31, 2014, the Company had approximately 218,000 MMBtu per day of firm sales contracted with third parties. Of these sales, 33,000 MMBtu per day, 5,000 MMBtu per day, 30,000 MMBtu per day, 50,000 MMBtu per day, 50,000 MMBtu per day and 50,000 MMBtu per day expire in 2015, 2016, 2017, 2018, 2019 and 2022, respectively.

Operating Leases

The Company leases office facilities under non-cancellable operating leases exceeding one year. Future minimum lease commitments under these leases at December 31, 2014 are as follows:

	(In thousands)
2015	\$ 615
2016	524
2017	451
2018	20
Total	<u>\$ 1,610</u>

The following table presents rent expense for the years ended December 31, 2014, 2013 and 2012, respectively.

	For the years ended December 31,		
	2014	2013	2012
	(In thousands)		
Minimum rentals	\$ 733	\$ 258	\$ 139
Less: Sublease rentals	15	45	7
	<u>\$ 718</u>	<u>\$ 213</u>	<u>\$ 132</u>

Other Commitments

Effective October 1, 2014, the Company entered into a Sand Supply Agreement with Muskie that expires on September 30, 2018. Pursuant to this agreement, the Company has agreed to purchase annual and monthly amounts of proppant sand subject to exceptions specified in the agreement at a fixed price per ton, subject to certain adjustments, plus agreed costs and expenses. Failure by either Muskie or the Company to deliver or accept the minimum monthly amount results in damages calculated per ton based on the difference between the monthly obligation amount and the amount actually delivered or accepted, as applicable. As of December 31, 2014, the Company had accrued \$0.3 million related to non-utilization fees.

Effective October 1, 2014, the Company entered into an Amended and Restated Master Services Agreement for pressure pumping services with Stingray Pressure that expires on September 30, 2018. Pursuant to this agreement, Stingray Pressure has agreed to provide hydraulic fracturing, stimulation and related completion and rework services to the Company and the Company has agreed to pay Stingray Pressure a monthly service fee plus the associated costs of the services provided.

Future minimum commitments under these agreements at December 31, 2014 are as follows:

	(In thousands)
2015	\$ 52,440
2016	52,440
2017	52,440
2018	39,330
Total	<u>\$ 196,650</u>

17. CONTINGENCIES

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

Concentration of Credit Risk

Gulfport operates in the oil and gas industry principally in the states of Ohio and Louisiana with sales to refineries, re-sellers such as pipeline companies, and local distribution companies. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the oil and gas industry, Gulfport believes that its level of credit-related losses due to such economic fluctuations has been immaterial and will continue to be immaterial to the Company's results of operations in the long term.

The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to \$250,000. At December 31, 2014, Gulfport held cash in excess of insured limits in these banks totaling \$140.9 million.

During the year ended December 31, 2014, Gulfport sold approximately 99% of its oil production to Shell Trading Company ("Shell"), 100% of its natural gas liquids production to MarkWest Utica and 40%, 32% and 19% of its natural gas production to BP, DTE Energy Trading Inc. and Hess, respectively. During the year ended December 31, 2013, Gulfport sold approximately 99% of its oil production to Shell, 100% of its natural gas liquids production to MarkWest Utica, and 32%, 31% and 17% of its natural gas production to Sequent Energy Management, L.P., Hess and Interstate Gas Supply, Inc., respectively. During the year ended December 31, 2012, Gulfport sold approximately 92% and 8% of its oil production to Shell and Diamondback O&G, respectively, 91% of its natural gas liquids production to Diamondback O&G and 41%, 18% and 16% of its natural gas production to Noble Americas Gas, Hess and Chevron, respectively.

18. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On October 17, 2012, December 21, 2012, and August 18, 2014, the Company issued an aggregate of \$600.0 million of its 7.75% Senior Notes. The October Notes and the December Notes were exchanged for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act. The Exchange Notes and the August Notes are collectively referred to as the "Notes". The Notes are guaranteed on a senior unsecured basis by all existing consolidated subsidiaries that guarantee the Company's secured revolving credit facility or certain other debt (the "Guarantors"). The Notes are not guaranteed by Grizzly Holdings, Inc., (the "Non-Guarantor"). The Guarantors are 100% owned by Gulfport (the "Parent"), and the guarantees are full, unconditional, joint and several. There are no significant restrictions on the ability of the Parent or the Guarantors to obtain funds from each other in the form of a dividend or loan.

In connection with the issuance of the August Notes, the Company and the subsidiary guarantors entered into a registration rights agreement with the initial purchasers on August 18, 2014, pursuant to which the Company and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the August Notes for a new issue of substantially identical debt securities registered under the Securities Act. The registration statement relating to the exchange offer for the August Notes was filed on November 6, 2014, as amended on February 3, 2015, and declared effective by the SEC on February 4, 2015. The exchange offer for the August Note is expected to be completed on or about March 10, 2015.

The following condensed consolidating balance sheets, statements of operations, statements of comprehensive income (loss) and statements of cash flows are provided for the Parent, the Guarantors and the Non-Guarantor and include the consolidating adjustments and eliminations necessary to arrive at the information for the Company on a condensed consolidated basis. The information has been presented using the equity method of accounting for the Parent's ownership of the Guarantors and the Non-Guarantor.

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	\$ 141,535	\$ 804	\$ 1	\$ —	\$ 142,340
Accounts receivable - oil and gas	103,762	96	—	—	103,858
Accounts receivable - related parties	46	—	—	—	46
Accounts receivable - intercompany	45,222	27	—	(45,249)	—
Prepaid expenses and other current assets	3,714	—	—	—	3,714
Short-term derivative instruments	78,391	—	—	—	78,391
Total current assets	372,670	927	1	(45,249)	328,349
Property and equipment:					
Oil and natural gas properties, full-cost accounting	3,887,874	35,990	—	(710)	3,923,154
Other property and equipment	18,301	43	—	—	18,344
Accumulated depletion, depreciation, amortization and impairment	(1,050,855)	(24)	—	—	(1,050,879)
Property and equipment, net	2,855,320	36,009	—	(710)	2,890,619
Other assets:					
Equity investments and investments in subsidiaries	360,238	—	180,217	(170,874)	369,581
Derivative instruments	24,448	—	—	—	24,448
Other assets	19,396	—	—	—	19,396
Total other assets	404,082	—	180,217	(170,874)	413,425
Total assets	\$ 3,632,072	\$ 36,936	\$ 180,218	\$ (216,833)	\$ 3,632,393
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	\$ 371,089	\$ 321	\$ —	\$ —	\$ 371,410
Accounts payable - intercompany	—	45,143	106	(45,249)	—
Asset retirement obligation - current	75	—	—	—	75
Deferred tax liability	27,070	—	—	—	27,070
Current maturities of long-term debt	168	—	—	—	168
Total current liabilities	398,402	45,464	106	(45,249)	398,723
Asset retirement obligation - long-term	17,863	—	—	—	17,863
Deferred tax liability	203,195	—	—	—	203,195
Long-term debt, net of current maturities	716,316	—	—	—	716,316
Total liabilities	1,335,776	45,464	106	(45,249)	1,336,097
Stockholders' equity:					
Common stock	856	—	—	—	856
Paid-in capital	1,828,602	322	227,079	(227,401)	1,828,602
Accumulated other comprehensive income (loss)	(26,675)	—	(26,675)	26,675	(26,675)
Retained earnings (accumulated deficit)	493,513	(8,850)	(20,292)	29,142	493,513
Total stockholders' equity	2,296,296	(8,528)	180,112	(171,584)	2,296,296
Total liabilities and stockholders' equity	\$ 3,632,072	\$ 36,936	\$ 180,218	\$ (216,833)	\$ 3,632,393

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	\$ 451,431	\$ 7,525	\$ —	\$ —	\$ 458,956
Accounts receivable - oil and gas	58,662	162	—	—	58,824
Accounts receivable - related parties	2,617	—	—	—	2,617
Accounts receivable - intercompany	21,379	27	—	(21,406)	—
Prepaid expenses and other current assets	2,581	—	—	—	2,581
Deferred tax asset	6,927	—	—	—	6,927
Short-term derivative instruments	324	—	—	—	324
Note receivable - related party	875	—	—	—	875
Total current assets	544,796	7,714	—	(21,406)	531,104
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	2,470,411	7,340	—	(573)	2,477,178
Other property and equipment	11,102	29	—	—	11,131
Accumulated depletion, depreciation, amortization and impairment	(784,695)	(22)	—	—	(784,717)
Property and equipment, net	1,696,818	7,347	—	(573)	1,703,592
Other assets:					
Equity investments and investments in subsidiaries	432,727	—	191,473	(184,132)	440,068
Derivative instruments	521	—	—	—	521
Other assets	17,851	—	—	—	17,851
Total other assets	451,099	—	191,473	(184,132)	458,440
Total assets	\$ 2,692,713	\$ 15,061	\$ 191,473	\$ (206,111)	\$ 2,693,136
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	\$ 190,284	\$ 423	\$ —	\$ —	\$ 190,707
Accounts payable - intercompany	—	21,296	110	(21,406)	—
Asset retirement obligation - current	795	—	—	—	795
Short-term derivative instruments	12,280	—	—	—	12,280
Current maturities of long-term debt	159	—	—	—	159
Total current liabilities	203,518	21,719	110	(21,406)	203,941
Long-term derivative instruments	11,366	—	—	—	11,366
Asset retirement obligation - long-term	14,288	—	—	—	14,288
Deferred tax liability	114,275	—	—	—	114,275
Long-term debt, net of current maturities	299,028	—	—	—	299,028
Total liabilities	642,475	21,719	110	(21,406)	642,898
Stockholders' equity:					
Common stock	851	—	—	—	851
Paid-in capital	1,813,058	322	208,277	(208,599)	1,813,058
Accumulated other comprehensive income (loss)	(9,781)	—	(9,781)	9,781	(9,781)
Retained earnings (accumulated deficit)	246,110	(6,980)	(7,133)	14,113	246,110
Total stockholders' equity	2,050,238	(6,658)	191,363	(184,705)	2,050,238
Total liabilities and stockholders' equity	\$ 2,692,713	\$ 15,061	\$ 191,473	\$ (206,111)	\$ 2,693,136

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	\$ 669,067	\$ 2,199	\$ —	\$ —	\$ 671,266
Costs and expenses:					
Lease operating expenses	51,238	953	—	—	52,191
Production taxes	23,803	203	—	—	24,006
Midstream gathering and processing	64,402	65	—	—	64,467
Depreciation, depletion and amortization	265,428	3	—	—	265,431
General and administrative	37,846	446	(2)	—	38,290
Accretion expense	761	—	—	—	761
Gain on sale of assets	(11)	—	—	—	(11)
	<u>443,467</u>	<u>1,670</u>	<u>(2)</u>	<u>—</u>	<u>445,135</u>
INCOME FROM OPERATIONS	<u>225,600</u>	<u>529</u>	<u>2</u>	<u>—</u>	<u>226,131</u>
OTHER (INCOME) EXPENSE:					
Interest expense	23,986	—	—	—	23,986
Interest income	(195)	—	—	—	(195)
Litigation settlement	25,500	—	—	—	25,500
Gain on contribution of investments	(84,470)	—	—	—	(84,470)
(Income) loss from equity method investments and investments in subsidiaries	(139,965)	—	13,159	(12,628)	(139,434)
	<u>(175,144)</u>	<u>—</u>	<u>13,159</u>	<u>(12,628)</u>	<u>(174,613)</u>
INCOME (LOSS) BEFORE INCOME TAXES	400,744	529	(13,157)	12,628	400,744
INCOME TAX EXPENSE	<u>153,341</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>153,341</u>
NET INCOME (LOSS)	<u>\$ 247,403</u>	<u>\$ 529</u>	<u>\$ (13,157)</u>	<u>\$ 12,628</u>	<u>\$ 247,403</u>

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	\$ 261,809	\$ 1,517	\$ —	\$ (573)	\$ 262,753
Costs and expenses:					
Lease operating expenses	25,971	732	—	—	26,703
Production taxes	26,848	85	—	—	26,933
Midstream gathering and processing	10,999	31	—	—	11,030
Depreciation, depletion and amortization	118,878	2	—	—	118,880
General and administrative	22,359	159	1	—	22,519
Accretion expense	717	—	—	—	717
Loss on sale of assets	508	—	—	—	508
	206,280	1,009	1	—	207,290
INCOME (LOSS) FROM OPERATIONS	55,529	508	(1)	(573)	55,463
OTHER (INCOME) EXPENSE:					
Interest expense	17,490	—	—	—	17,490
Interest income	(297)	—	—	—	(297)
(Income) loss from equity method investments and investments in subsidiaries	(212,992)	—	2,999	(3,065)	(213,058)
	(195,799)	—	2,999	(3,065)	(195,865)
INCOME (LOSS) BEFORE INCOME TAXES	251,328	508	(3,000)	2,492	251,328
INCOME TAX EXPENSE	98,136	—	—	—	98,136
NET INCOME (LOSS)	\$ 153,192	\$ 508	\$ (3,000)	\$ 2,492	\$ 153,192

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	\$ 247,637	\$ 1,289	\$ —	\$ —	\$ 248,926
Costs and expenses:					
Lease operating expenses	23,644	664	—	—	24,308
Production taxes	28,874	83	—	—	28,957
Midstream gathering and processing	432	11	—	—	443
Depreciation, depletion and amortization	90,749	—	—	—	90,749
General and administrative	13,602	132	74	—	13,808
Accretion expense	698	—	—	—	698
Gain on sale of assets	(7,300)	—	—	—	(7,300)
	<u>150,699</u>	<u>890</u>	<u>74</u>	<u>—</u>	<u>151,663</u>
INCOME (LOSS) FROM OPERATIONS	<u>96,938</u>	<u>399</u>	<u>(74)</u>	<u>—</u>	<u>97,263</u>
OTHER (INCOME) EXPENSE:					
Interest expense	7,458	—	—	—	7,458
Interest income	(72)	—	—	—	(72)
(Income) loss from equity method investments and investments in subsidiaries	(5,182)	—	1,512	(4,652)	(8,322)
	<u>2,204</u>	<u>—</u>	<u>1,512</u>	<u>(4,652)</u>	<u>(936)</u>
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	94,734	399	(1,586)	4,652	98,199
INCOME TAX EXPENSE	<u>26,363</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>26,363</u>
INCOME (LOSS) FROM CONTINUING OPERATIONS	<u>68,371</u>	<u>399</u>	<u>(1,586)</u>	<u>4,652</u>	<u>71,836</u>
DISCONTINUED OPERATIONS					
Loss on disposal of Belize properties, net of tax	—	3,465	—	—	3,465
NET INCOME (LOSS)	<u>\$ 68,371</u>	<u>\$ (3,066)</u>	<u>\$ (1,586)</u>	<u>\$ 4,652</u>	<u>\$ 68,371</u>

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Amounts in thousands)

	Year Ended December 31, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	\$ 247,403	\$ 529	\$ (13,157)	\$ 12,628	\$ 247,403
Foreign currency translation adjustment	(16,894)	—	(16,894)	16,894	(16,894)
Other comprehensive income (loss)	(16,894)	—	(16,894)	16,894	(16,894)
Comprehensive income	<u>\$ 230,509</u>	<u>\$ 529</u>	<u>\$ (30,051)</u>	<u>\$ 29,522</u>	<u>\$ 230,509</u>

	Year Ended December 31, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	\$ 153,192	\$ 508	\$ (3,000)	\$ 2,492	\$ 153,192
Foreign currency translation adjustment	(12,223)	—	(12,223)	12,223	(12,223)
Change in fair value of derivative instruments, net of taxes	(4,419)	—	—	—	(4,419)
Reclassification of settled contracts, net of taxes	10,290	—	—	—	10,290
Other comprehensive income (loss)	(6,352)	—	(12,223)	12,223	(6,352)
Comprehensive income	<u>\$ 146,840</u>	<u>\$ 508</u>	<u>\$ (15,223)</u>	<u>\$ 14,715</u>	<u>\$ 146,840</u>

	Year Ended December 31, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	\$ 68,371	\$ (3,066)	\$ (1,586)	\$ 4,652	\$ 68,371
Foreign currency translation adjustment	1,355	—	1,355	(1,355)	1,355
Change in fair value of derivative instruments, net of taxes	(8,452)	—	—	—	(8,452)
Reclassification of settled contracts, net of taxes	1,005	—	—	—	1,005
Other comprehensive income (loss)	(6,092)	—	1,355	(1,355)	(6,092)
Comprehensive income	<u>\$ 62,279</u>	<u>\$ (3,066)</u>	<u>\$ (231)</u>	<u>\$ 3,297</u>	<u>\$ 62,279</u>

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Year Ended December 31, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	\$ 388,177	\$ 21,698	\$ (2)	\$ —	\$ 409,873
Net cash provided by (used in) investing activities	(1,108,241)	(28,419)	(18,799)	18,802	(1,136,657)
Net cash provided by (used in) financing activities	410,168	—	18,802	(18,802)	410,168
Net increase (decrease) in cash and cash equivalents	(309,896)	(6,721)	1	—	(316,616)
Cash and cash equivalents at beginning of period	451,431	7,525	—	—	458,956
Cash and cash equivalents at end of period	\$ 141,535	\$ 804	\$ 1	\$ —	\$ 142,340

	Year Ended December 31, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	\$ 182,961	\$ 8,104	\$ —	\$ —	\$ 191,065
Net cash provided by (used in) investing activities	(661,886)	(2,374)	(33,929)	33,929	(664,260)
Net cash provided by (used in) financing activities	765,063	—	33,929	(33,929)	765,063
Net increase in cash and cash equivalents	286,138	5,730	—	—	291,868
Cash and cash equivalents at beginning of period	165,293	1,795	—	—	167,088
Cash and cash equivalents at end of period	\$ 451,431	\$ 7,525	\$ —	\$ —	\$ 458,956

	Year Ended December 31, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	\$ 195,734	\$ 3,425	\$ (1)	\$ —	\$ 199,158
Net cash provided by (used in) investing activities	(838,177)	(2,402)	(103,915)	103,915	(840,579)
Net cash provided by (used in) financing activities	714,612	—	103,915	(103,915)	714,612
Net increase (decrease) in cash and cash equivalents	72,169	1,023	(1)	—	73,191
Cash and cash equivalents at beginning of period	93,124	772	1	—	93,897
Cash and cash equivalents at end of period	\$ 165,293	\$ 1,795	\$ —	\$ —	\$ 167,088

**19. SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(UNAUDITED)**

As discussed above in Notes 4 and 5, the Company did not own any of Diamondback's common stock at December 31, 2014. However, at December 31, 2013 and December 31, 2012, the Company owned a 7.2% and 21.4% equity interest in Diamondback, respectively, which interest is shown below. The Company also owns a 24.9999% interest in Grizzly, which interest is shown below. Grizzly achieved first production in 2014, therefore, interest in Grizzly is shown only for 2014.

The following is historical revenue and cost information relating to the Company's oil and gas operations located entirely in the United States:

Capitalized Costs Related to Oil and Gas Producing Activities

	2014	2013
	(In thousands)	
Proven properties	\$ 2,457,616	\$ 1,526,588
Unproven properties	1,465,538	950,590
	3,923,154	2,477,178
Accumulated depreciation, depletion, amortization and impairment reserve	(1,044,273)	(779,561)
Net capitalized costs	\$ 2,878,881	\$ 1,697,617
<i>Equity investment in Diamondback Energy, Inc.</i>		
Proven properties	\$ —	\$ 92,074
Unproven properties	—	26,608
	—	118,682
Accumulated depreciation, depletion, amortization and impairment reserve	—	(15,180)
Net capitalized costs	\$ —	\$ 103,502
<i>Equity investment in Grizzly Oil Sand ULC</i>		
Proven properties	\$ 96,859	\$ —
Unproven properties	103,160	—
	200,019	—
Accumulated depreciation, depletion, amortization and impairment reserve	(1,248)	—
Net capitalized costs	\$ 198,771	\$ —

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	2014	2013	2012
(In thousands)			
Acquisition	\$ 440,288	\$ 338,153	\$ 513,904
Development of proved undeveloped properties	864,511	408,121	121,787
Exploratory	2,249	26,174	93,397
Recompletions	45,658	44,633	24,643
Capitalized asset retirement obligation	2,095	3,556	2,195
Total	<u>\$ 1,354,801</u>	<u>\$ 820,637</u>	<u>\$ 755,926</u>

Equity investment in Diamondback Energy, Inc.

Acquisition	\$ —	\$ 44,534	\$ 49,895
Development of proved undeveloped properties	—	6,369	22,740
Exploratory	—	17,491	3,755
Capitalized asset retirement obligation	—	50	203
Total	<u>\$ —</u>	<u>\$ 68,444</u>	<u>\$ 76,593</u>

Equity investment in Grizzly Oil Sands ULC

Acquisition	\$ 1,230	\$ —	\$ —
Development of proved undeveloped properties	7,107	—	—
Exploratory	—	—	—
Capitalized asset retirement obligation	1,055	—	—
Total	<u>\$ 9,392</u>	<u>\$ —</u>	<u>\$ —</u>

Results of Operations for Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and gas. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization allowances, after giving effect to the permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas production.

	2014	2013	2012
	(In thousands)		
Revenues	\$ 670,762	\$ 262,225	\$ 248,601
Production costs	(140,664)	(64,666)	(53,708)
Depletion	(263,946)	(118,118)	(90,230)
	<u>266,152</u>	<u>79,441</u>	<u>104,663</u>
Income tax expense (benefit)			
Current	—	—	730
Deferred	96,061	49,447	25,633
	<u>96,061</u>	<u>49,447</u>	<u>26,363</u>
Results of operations from producing activities	\$ 170,091	\$ 29,994	\$ 78,300
Depletion per Mcf of gas equivalent (Mcf)	\$ 3.01	\$ 4.78	\$ 5.85

Results of Operations from equity method investment in Diamondback Energy, Inc.

Revenues	\$ —	\$ 14,976	\$ 16,042
Production costs	—	(2,518)	(4,474)
Depletion	—	(4,754)	(5,515)
	<u>—</u>	<u>7,704</u>	<u>6,053</u>
Income tax expense	—	2,286	2,158
Results of operations from producing activities	\$ —	\$ 5,418	\$ 3,895

Results of Operations from equity method investment in Grizzly Oil Sands ULC

Revenues	\$ 5,449	\$ —	\$ —
Production costs	(10,113)	—	—
Depletion	(1,195)	—	—
	<u>(5,859)</u>	<u>—</u>	<u>—</u>
Income tax expense	—	—	—
Results of operations from producing activities	\$ (5,859)	\$ —	\$ —

Oil and Gas Reserves

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2014, 2013 and 2012 and changes in proved reserves during the last three years. The reserve reports use 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, 2014, 2013 and 2012, in accordance with guidelines of the SEC applicable to reserves estimates. Volumes for oil are stated in thousands of barrels (MBbls) and volumes for gas are stated in millions of cubic feet (MMcf). The prices used for the 2014 reserve report are \$94.99 per barrel of oil, \$4.35 per MMBtu and \$44.84 per barrel for NGLs, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively. The prices used at December 31, 2013 and 2012 for reserve report purposes are \$96.78 per barrel, \$3.67 per MMBtu and \$41.23 per barrel for NGLs and \$91.32 per barrel and \$2.76 per MMBtu, respectively.

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

	2014			2013			2012		
	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)
Proved Reserves									
Beginning of the period	8,346	146,446	5,675	8,106	33,771	145	13,954	15,728	2,791
Purchases in oil and gas reserves in place	173	8,863	353	—	—	—	—	—	—
Extensions and discoveries	4,975	629,151	22,594	2,765	123,597	5,850	4,732	31,265	148
Sales of oil and gas reserves in place	—	—	—	—	—	—	(7,875)	(11,757)	(2,729)
Revisions of prior reserve estimates	(1,313)	(6,136)	(304)	(208)	(2,031)	—	(382)	(357)	—
Current production	(2,684)	(59,318)	(2,050)	(2,317)	(8,891)	(320)	(2,323)	(1,108)	(65)
End of period	<u>9,497</u>	<u>719,006</u>	<u>26,268</u>	<u>8,346</u>	<u>146,446</u>	<u>5,675</u>	<u>8,106</u>	<u>33,771</u>	<u>145</u>
Proved developed reserves	<u>5,719</u>	<u>345,166</u>	<u>12,379</u>	<u>5,609</u>	<u>94,552</u>	<u>3,527</u>	<u>5,175</u>	<u>18,482</u>	<u>44</u>
Proved undeveloped reserves	<u>3,778</u>	<u>373,840</u>	<u>13,889</u>	<u>2,737</u>	<u>51,894</u>	<u>2,148</u>	<u>2,931</u>	<u>15,289</u>	<u>101</u>
<i>Equity investment in Diamondback Energy, Inc.</i>									
Proved Reserves									
Beginning of the period	—	—	—	5,606	7,398	1,766	3,874	4,398	1,080
Change in ownership interest in Diamondback	—	—	—	(3,720)	(4,909)	(1,171)	—	—	—
Purchases in oil and gas reserves in place	—	—	—	528	752	120	1,543	2,292	540
Extensions and discoveries	—	—	—	1,227	1,741	331	665	804	186
Revisions of prior reserve estimates	—	—	—	(428)	(417)	(249)	(314)	82	(1)
Current production	—	—	—	(146)	(124)	(26)	(162)	(178)	(39)
End of period	<u>—</u>	<u>—</u>	<u>—</u>	<u>3,067</u>	<u>4,441</u>	<u>771</u>	<u>5,606</u>	<u>7,398</u>	<u>1,766</u>
Proved developed reserves	<u>—</u>	<u>—</u>	<u>—</u>	<u>1,425</u>	<u>2,263</u>	<u>358</u>	<u>1,539</u>	<u>2,753</u>	<u>641</u>
Proved undeveloped reserves	<u>—</u>	<u>—</u>	<u>—</u>	<u>1,642</u>	<u>2,178</u>	<u>413</u>	<u>4,068</u>	<u>4,645</u>	<u>1,124</u>
<i>Equity investment in Grizzly Oil Sands ULC</i>									
Beginning of the period	13,637	—	—	—	—	—	—	—	—
Purchases in oil and gas reserves in place	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	—	—	—	—	—	—	—	—
Revisions of prior reserve estimates	990	—	—	—	—	—	—	—	—
Current production	(69)	—	—	—	—	—	—	—	—
End of period	<u>14,558</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>
Proved developed reserves	<u>1,632</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>
Proved undeveloped reserves	<u>12,926</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>

In 2014, the Company experienced extensions and discoveries of 786,347 million cubic feet of gas equivalent (MMcfe) of proved reserves attributable to the development of the Company's Utica Shale acreage. In addition, the Company experienced downward revisions of 15,837 MMcfe in estimated proved reserves in 2014 primarily due to the exclusion of PUD locations in our Southern Louisiana and Utica fields that were not expected to be drilled within five years of initial booking. The Company also purchased 12,019 MMcfe of proved reserves as a result of its acquisition from Rhino discussed in Note 2. In 2013, the Company experienced extensions and discoveries of 166,832 MMcfe of proved reserves attributable to the development of the Company's Utica Shale acreage. The Company contributed its Permian Basin assets to Diamondback in 2012, as discussed in Note 4, resulting in a decrease of 75,384 MMcfe in estimated proved reserves in 2012. The Company experienced extensions and discoveries of proved reserves of 40,049 MMcfe in 2012 attributable to the discovery and development of the Company's Utica Shale acreage. In addition, the Company experienced downward reserve revisions of 2,649 MMcfe in estimated proved reserves in 2012 primarily due to a change in the drilling schedule of its Niobrara acreage.

Discounted Future Net Cash Flows

The following tables present the estimated future cash flows, and changes therein, from Gulfport's proven oil and gas reserves as of December 31, 2014, 2013 and 2012 using an unweighted average first-of-the-month price for the period January through December 31, 2014, 2013 and 2012.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Future cash flows	\$ 4,667,678	\$ 1,657,708	\$ 954,833
Future development and abandonment costs	(719,898)	(272,500)	(159,113)
Future production costs	(880,427)	(274,428)	(147,024)
Future production taxes	(71,229)	(78,647)	(89,175)
Future income taxes	(693,154)	(172,691)	(114,867)
Future net cash flows	2,302,970	859,442	444,654
10% discount to reflect timing of cash flows	(875,803)	(280,976)	(96,013)
Standardized measure of discounted future net cash flows	<u>\$ 1,427,167</u>	<u>\$ 578,466</u>	<u>\$ 348,641</u>

Equity investment in Diamondback Energy, Inc. Standardized measure of discounted cash flows

Future cash flows	\$ —	\$ 331,505	\$ 592,669
Future development and abandonment costs	—	(37,229)	(115,869)
Future production costs	—	(58,096)	(165,553)
Future production taxes	—	(22,925)	(30,122)
Future income taxes	—	(48,547)	(71,669)
Future net cash flows	—	164,708	209,456
10% discount to reflect timing of cash flows	—	(94,462)	(130,871)
Standardized measure of discounted future net cash flows	<u>\$ —</u>	<u>\$ 70,246</u>	<u>\$ 78,585</u>

Equity investment in Grizzly Oil Sands ULC Standardized measure of discounted cash flows

Future cash flows	\$ 754,720	\$ —	\$ —
Future development and abandonment costs	(205,242)	—	—
Future production costs	(291,988)	—	—
Future production taxes	—	—	—
Future income taxes	(11,250)	—	—
Future net cash flows	246,240	—	—
10% discount to reflect timing of cash flows	(152,494)	—	—
Standardized measure of discounted future net cash flows	<u>\$ 93,746</u>	<u>\$ —</u>	<u>\$ —</u>

In order to develop its proved undeveloped reserves according to the drilling schedule used by the engineers in Gulfport's reserve report, the Company will need to spend \$221.0 million, \$93.1 million and \$215.4 million during years 2015, 2016 and 2017, respectively.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Year ended December 31,		
	2014	2013	2012
	(In thousands)		
Sales and transfers of oil and gas produced, net of production costs	\$ (530,098)	\$ (197,559)	\$ (194,893)
Net changes in prices, production costs, and development costs	97,716	65,573	108,941
Acquisition of oil and gas reserves in place	14,266	—	—
Extensions and discoveries	790,533	130,826	151,654
Previously estimated development costs incurred during the period	68,227	43,478	10,211
Revisions of previous quantity estimates, less related production costs	(37,801)	(3,591)	(10,504)
Sales of reserves in place	—	—	(214,867)
Accretion of discount	57,847	34,864	37,668
Net changes in income taxes	(295,226)	(30,239)	25,585
Change in production rates and other	683,237	186,473	58,165
Total change in standardized measure of discounted future net cash flows	\$ 848,701	\$ 229,825	\$ (28,040)

Equity investment in Diamondback Energy, Inc. Changes in standardized measure of discounted cash flows

Change in ownership interest in Diamondback	\$ —	\$ (52,145)	\$ —
Sales and transfers of oil and gas produced, net of production costs	—	(12,524)	(11,601)
Net changes in prices, production costs, and development costs	—	3,312	(14,596)
Acquisition of oil and gas reserves in place	—	21,968	23,090
Extensions and discoveries	—	39,776	16,969
Previously estimated development costs incurred during the period	—	5,517	19,014
Revisions of previous quantity estimates, less related production costs	—	(9,143)	(4,897)
Accretion of discount	—	4,175	7,803
Net changes in income taxes	—	(12,137)	(26,866)
Change in production rates and other	—	2,862	(8,358)
Total change in standardized measure of discounted future net cash flows	\$ —	\$ (8,339)	\$ 558

Equity investment in Grizzly Oil Sands ULC Changes in standardized measure of discounted cash flows

Sales and transfers of oil and gas produced, net of production costs	\$ 4,664	\$ —	\$ —
Net changes in prices, production costs, and development costs	(76,518)	—	—
Acquisition of oil and gas reserves in place	—	—	—
Extensions and discoveries	7,107	—	—
Previously estimated development costs incurred during the period	—	—	—
Revisions of previous quantity estimates, less related production costs	10,659	—	—
Accretion of discount	14,946	—	—
Net changes in income taxes	9,162	—	—
Change in production rates and other	(25,738)	—	—
Total change in standardized measure of discounted future net cash flows	\$ (55,718)	\$ —	\$ —

20. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table summarizes quarterly financial data for the years ended December 31, 2014 and 2013:

	2014			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	\$ 118,029	\$ 114,736	\$ 170,804	\$ 267,697
Income from operations	25,109	18,110	53,454	129,458
Income tax expense	49,247	31,461	4,876	67,757
Net income	82,558	47,852	6,920	110,073
Income per share:				
Basic	\$ 0.97	\$ 0.56	\$ 0.08	\$ 1.29
Diluted	\$ 0.96	\$ 0.56	\$ 0.08	\$ 1.28
	2013			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	\$ 55,000	\$ 70,434	\$ 69,252	\$ 68,067
Income from operations	14,944	22,456	15,137	2,926
Income tax expense	28,195	25,514	23,400	21,027
Net income	44,559	43,828	40,527	24,278
Income per share:				
Basic	\$ 0.61	\$ 0.57	\$ 0.52	\$ 0.30
Diluted	\$ 0.61	\$ 0.56	\$ 0.52	\$ 0.30

21. SUBSEQUENT EVENTS

In January and February of 2015, the Company entered into fixed price swaps for 1,000 barrels of oil per day at a weighted average price of \$62.25 per barrel. For the period of September 2015 through December 2015, the Company entered into fixed price swaps for 30,000 MMBtu of natural gas per day at a weighted average price of \$3.40 per MMBtu. For the period from January 2016 through December 2017, the Company entered into fixed price swaps for 80,000 MMBtu of natural gas per day at a weighted average price of \$3.45 per MMBtu. For the period from January 2018 through December 2018, the Company entered into fixed price swaps for 30,000 MMBtu of natural gas per day at a weighted average price of \$3.40 per MMBtu. The Company's fixed price swap contracts are tied to the commodity prices on NYMEX. The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX for natural gas.

In February 2015, the Company entered into natural gas basis swap positions, which settle on the pricing index to basis differential of MichCon to the NYMEX Henry Hub natural gas price for 30,000 MMBtu per day at a hedge differential of \$.02 for the period from March 2015 through December 2016 and for 10,000 MMBtu per day at a hedge differential of \$.01 for the period from March 2015 through December 2016.

ITEM 6. EXHIBITS

Exhibit Number	Description
2.1	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).
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	Certificate of Amendment No. 2 to 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 July 23, 2013).
3.4	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).
3.5	First Amendment to the 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 23, 2013).
3.6	Second Amendment to the Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on May 2, 2014).
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	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).
4.3	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).
4.4	Second Supplemental Indenture, dated August 18, 2014, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on August 19, 2014).
4.5	Registration Rights Agreement, dated as of August 18, 2014, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.4 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on August 19, 2014).
10.1+	2013 Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form S-4, File No. 333-189992, filed by the Company with the SEC on July 17, 2013).
10.2+	2014 Executive Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 7, 2014).
10.3+	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).
10.4+	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to the Form 10-K, File No. 000-19514, filed by the Company with the SEC on February 28, 2014).
10.5+	Consulting Agreement, effective as of June 14, 2013, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on June 19, 2013).
10.6+	Separation and Release Agreement, dated as of January 31, 2014, by and between the Company and James D. Palm (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 4, 2014).

- 10.7+ Employment Agreement, entered into on April 30, 2014, by and between Gulfport Energy Corporation and Michael G. Moore (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S-4/A, File No. 333-199905, filed by the Company with the SEC on February 3, 2015).
- 10.8 Amended and Restated Credit Agreement, dated as of December 27, 2013, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 3, 2014).
- 10.9 First Amendment to Amended and Restated Credit Agreement, dated as of April 23, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 28, 2014).
- 10.10 Second Amendment to Amended and Restated Credit Agreement, dated as of November 26, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 3, 2014).
- 10.11# Sand Supply Agreement, effective as of October 1, 2014, by and between Muskie Proppant LLC and Gulfport Energy Corporation (incorporated by reference to Exhibit 10.1 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 7, 2014).
- 10.12# Amended and Restated Master Services Agreement, effective as of October 1, 2014, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 7, 2014).
- 10.13+ Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-4, File No. 333-199905, filed by the Company with the SEC on November 6, 2014).
- 10.14 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 Ryder Scott Company.
- 23.3* Consent of Netherland, Sewell & Associates, Inc.
- 23.4* Consent of Grant Thornton LLP with respect to financial statements of Diamondback Energy, Inc.
- 31.1* Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
- 31.2* Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
- 32.1** Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
- 32.2** Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
- 99.1* Report of Ryder Scott Company.
- 99.2* Report of Netherland, Sewell & Associates, Inc.
- 101.INS* XBRL Instance Document.
- 101.SCH* XBRL Taxonomy Extension Schema Document.
- 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.
- # Confidential treatment with respect to certain portions of this agreement was granted by the SEC on January 16, 2015, which portions have been omitted and filed separately with the SEC.

SUBSIDIARIES OF GULFPORT ENERGY CORPORATION

<u>Name of Subsidiary</u>	<u>Jurisdiction of Organization</u>
Grizzly Holdings, Inc.	Delaware
Jaguar Resources LLC	Delaware
Puma Resources, Inc.	Delaware
Gator Marine, Inc.	Delaware
Gator Marine Ivanhoe, Inc.	Delaware
Westhawk Minerals LLC	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 27, 2015, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Gulfport Energy Corporation on Form 10-K for the year ended December 31, 2014. We hereby consent to the incorporation by reference of said reports in the Registration Statements of Gulfport Energy Corporation on Forms S-8 (File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001), and on Form S-3ASR (File No. 333-192113, automatically effective November 6, 2013).

/s/ GRANT THORNTON LLP

Oklahoma City, OK
February 27, 2015

CONSENT OF RYDER SCOTT COMPANY, L.P.

We have issued our report dated January 16, 2015 for the year ended December 31, 2014 on estimates of proved reserves and future net cash flows of certain oil and natural gas properties located in the Utica Shale of Eastern Ohio of Gulfport Energy Corporation ("Gulfport"). As independent oil and gas consultants, we hereby consent to the inclusion of our report and the information contained therein and information from our prior reserve reports in this Annual Report on Form 10-K of Gulfport (this "Annual Report") and to all references to our firm in this Annual Report. We hereby also consent to the incorporation by reference of such reports and the information contained therein in the Registration Statements of Gulfport on Forms S-8 (File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001), and on Form S-3ASR (File No. 333-192113, automatically effective November 6, 2013).

RYDER SCOTT COMPANY, L.P.

/s/ RYDER SCOTT COMPANY, L.P.

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

February 27, 2015
Oklahoma City, Oklahoma

CONSENT OF NETHERLAND, SEWELL & ASSOCIATES, INC.

We hereby consent to the inclusion in the Form 10-K of Gulfport Energy Corporation (the "Form 10-K") of our report dated January 14, 2015 on oil and gas reserves of Gulfport Energy Corporation and its subsidiaries as of December 31, 2014 located in Colorado and Louisiana and information from our prior reserve reports, to all references to our firm included in the Form 10-K and to the incorporation by reference of all such reports in the Registration Statements of Gulfport Energy Corporation on Forms S-8 (File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001), and on Form S-3ASR (File No. 333-192113, automatically effective November 6, 2013).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/J. CARTER HENSON, JR.

J. Carter Henson, Jr., P.E.
Senior Vice President

Houston, Texas
February 27, 2015

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 19, 2015, with respect to the consolidated financial statements included in the Annual Report of Diamondback Energy, Inc. on Form 10-K for the year ended December 31, 2014 and incorporated by reference in the Annual Report of Gulfport Energy Corporation on Form 10-K for the year ended December 31, 2014. We hereby consent to the incorporation by reference of said report in the Registration Statements of Gulfport Energy Corporation on Forms S-8 (File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001), on Form S-3 (File No. 333-168180, effective July 28, 2010) and on Form S-3ASR (File No. 333-175435, automatically effective July 11, 2011).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 27, 2015

CERTIFICATION

I, Michael G. Moore, Chief Executive Officer of Gulfport Energy Corporation, certify that:

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

Date: February 27, 2015

/s/ Michael G. Moore

Michael G. Moore

Chief Executive Officer and President

CERTIFICATION

I, Aaron Gaydosik, Chief Financial Officer of Gulfport Energy Corporation, certify that:

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

Date: February 27, 2015

/s/ Aaron Gaydosik
Aaron Gaydosik
Chief Financial Officer

CERTIFICATION OF PERIODIC REPORT

I, Michael G. Moore, Chief Executive Officer of Gulfport Energy Corporation (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

- (1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 27, 2015

/s/ Michael G. Moore

Michael G. Moore

Chief Executive Officer and President

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

CERTIFICATION OF PERIODIC REPORT

I, Aaron Gaydosik, Chief Financial Officer of Gulfport Energy Corporation (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

- (1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and
- (2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 27, 2015

/s/ Aaron Gaydosik

Aaron Gaydosik

Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.



RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

January 16, 2015

Gulfport Energy Corporation
 14313 N. May, Suite 100
 Oklahoma City, Oklahoma 73134

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of Gulfport Energy Corporation (Gulfport) as of December 31, 2014. The subject properties are located in the state of Ohio. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 12, 2015, and presented herein, was prepared for public disclosure by Gulfport in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Gulfport in the Ohio Utica Shale as of December 31, 2014. The results of this study are summarized below.

SEC PARAMETERS
 Estimated Net Reserves and Income Data
 Certain Leasehold Interests of
Gulfport Energy Corporation

As of December 31, 2014

	Proved		
	Developed Producing	Undeveloped	Total Proved
<i>Net Remaining Reserves</i>			
Oil/Condensate - Mbbl	2,143	3,269	5,412
Plant Products - Mbbl	12,379	13,889	26,268
Gas - MMCF	343,222	373,683	716,905
MBOE	71,726	79,438	151,164
<i>Income Data (\$M)</i>			
Future Gross Revenue	1,989,720	\$ 2,254,206	\$ 4,243,926
Deductions	<u>420,576</u>	<u>1,002,277</u>	<u>1,422,853</u>
Future Net Income (FNI)	\$ 1,569,144	\$ 1,251,929	\$ 2,821,073
Discounted FNI @ 10%	\$ 1,094,346	\$ 595,373	\$ 1,689,719

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

The estimated reserves and future net income amounts presented in this report, as of December 31, 2014, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report.

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

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 40.5 percent and gas reserves account for the remaining 59.5 percent of total future gross revenue from proved reserves.

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

Discount Rate Percent	Discounted Future Net Income (\$M) As of December 31, 2014	
	Total	Proved
5	\$2,114,525	
15	\$1,409,936	
20	\$1,212,949	
25	\$1,067,208	

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

Reserves Included in This Report

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

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report.

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

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

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

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

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

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Gulfport owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor

were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

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

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

The proved reserves for the properties included herein were estimated by performance methods, analogy, or a combination of these methods. Approximately 90 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through November 2014 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Gulfport and were considered sufficient for the purpose thereof. The remaining 10 percent of the proved producing reserves were estimated by analogy, or a combination of analogy and performance. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data alone as a basis for the reserve estimates was considered to be inappropriate.

All of the proved undeveloped reserves included herein were estimated by the analogy method. The data utilized from the analogues were considered sufficient for the purpose thereof.

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

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

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

Future Production Rates

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

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

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to,

reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

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

Gulfport furnished us with the above mentioned average prices in effect on December 31, 2014. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

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

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

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	\$94.99/Bbl	\$84.49/Bbl
	NGLs	Propane, Mt. Belvieu	\$44.84/Bbl	\$48.44/Bbl
	Gas	Henry Hub	\$4.35/MMBTU	\$3.54/MCF

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

Costs

Operating costs for the leases and wells in this report were furnished by Gulfport and are based on the operating expense reports of Gulfport and include only those costs directly applicable to the leases or

wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Gulfport. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

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

The proved undeveloped reserves in this report have been incorporated herein in accordance with Gulfport's plans to develop these reserves as of December 31, 2014. The implementation of Gulfport's development plans as presented to us and incorporated herein is subject to the approval process adopted by Gulfport's management. As the result of our inquiries during the course of preparing this report, Gulfport has informed us that the development activities included herein have been subjected to and received the internal approvals required by Gulfport's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Gulfport. Additionally, Gulfport has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans.

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

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

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

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

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

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

Terms of Usage

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

Gulfport makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Gulfport has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Gulfport of the references to our name as well as to the references to our third party report for Gulfport, which appears in the December 31, 2014 annual report on Form 10-K of Gulfport. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Gulfport.

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

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

Very truly yours,

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

\s\ Don P. Griffin

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

DPG (FWZ)/pl

[SEAL]



January 14, 2015

Mr. Michael G. Moore
 Gulfport Energy Corporation
 14313 North May Avenue, Suite 100
 Oklahoma City, Oklahoma 73134

Dear Mr. Moore:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2014, to the Gulfport Energy Corporation (Gulfport) interest in certain oil and gas properties located in Colorado and Louisiana. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 3 percent of all proved reserves owned by Gulfport. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, *Extractive Activities-Oil and Gas*, except that *future income taxes are excluded and, as requested, per-well overhead expenses are excluded*. Definitions are presented immediately following this letter. This report has been prepared for Gulfport's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Gulfport interest in these properties, as of December 31, 2014, to be:

Category	Net Reserves		Future Net Revenue (M\$)	
	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	1,230.9	776.2	55,461.0	53,100.7
Proved Developed Non-Producing	2,222.8	1,036.2	98,378.0	82,367.8
Proved Undeveloped	509.7	156.8	12,767.5	9,708.4
Total Proved	3,963.4	1,969.1	166,606.5	145,176.9

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable reserves that exist for these properties have not been included. No study was made to determine whether possible reserves might be established for these properties. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys



the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Gulfport's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Gulfport's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2014. For oil volumes, the average Shell Trading (US) Company West Texas/New Mexico Intermediate posted price of \$91.60 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of \$4.350 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are \$96.73 per barrel of oil and \$3.453 per MCF of gas.

Operating costs used in this report are based on operating expense records of Gulfport, the operator of the properties, and include only direct lease- and field-level costs. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. As requested, these costs do not include the per-well overhead expenses allowed under joint operating agreements, nor do they include the headquarters general and administrative overhead expenses of Gulfport. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Gulfport and are based on actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Gulfport's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Gulfport interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Gulfport receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Gulfport, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.



For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for behind-pipe zones, non-producing zones, and undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Gulfport, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Derek F. Newton, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1997 and has over 14 years of prior industry experience. Edward C. Roy III, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Derek F. Newton /s/ Edward C. Roy III
By: Derek F. Newton, P.E. 97689 Edward C. Roy III, P.G. 2364
Vice President Vice President

Date Signed: January 14, 2015

Date Signed: January 14, 2015



DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production



for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
- (iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
- (iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
 - (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
 - (iii) Dry hole contributions and bottom hole contributions.
 - (iv) Costs of drilling and equipping exploratory wells.
 - (v) Costs of drilling exploratory-type stratigraphic test wells.
-



(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

- (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
- (B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
- (C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
 - (1) Lifting the oil and gas to the surface;
 - and
 - (2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons);
 - and
- (D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

- a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
- b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

- (A) Transporting, refining, or marketing oil and gas;
 - (B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
-



- (C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
- (D) Production of geothermal steam.

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

- (i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
- (ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
- (iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
- (iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
- (v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
- (vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

- (i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
- (ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
- (iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
- (iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.



(20) *Production costs.*

- (i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:
 - (A) Costs of labor to operate the wells and related equipment and facilities.
 - (B) Repairs and maintenance.
 - (C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
 - (D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
 - (E) Severance taxes.
- (ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

- (i) The area of the reservoir considered as proved includes:
 - (A) The area identified by drilling and limited by fluid contacts, if any, and
 - (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
 - (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
 - (iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
 - (iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
 - (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an
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analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

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

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

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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

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

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

- a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

- a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*



b. *Future development and production costs.* These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. *Future income tax expenses.* These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d. *Future net cash flows.* These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. *Discount.* This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f. *Standardized measure of discounted future net cash flows.* This amount is the future net cash flows less the computed discount.

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

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

- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
- (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects - such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations - by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);

The company's historical record at completing development of comparable long-term projects;

The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;



The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and

The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

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

(32) *Unproved properties.* Properties with no proved reserves.