The background of the entire page is a dark blue, textured topographic map. The map features numerous contour lines of varying thickness and spacing, representing different elevations. Some contour lines are labeled with numbers such as 100, 200, 300, 400, 500, 600, 700, 800, 900, and 1000. The lines are more densely packed in some areas, indicating steeper slopes, and more widely spaced in others, indicating flatter terrain. The overall effect is a sense of ruggedness and depth.

ON

SOLID

ROCK

GULFPORT ENERGY / 2015 ANNUAL REPORT



AS WE LOOK TOWARD THE FUTURE, IT IS OUR INTENT TO EXIT THIS COMMODITY PRICE CYCLE EVEN **STRONGER THAN WHEN WE ENTERED.**

2015 was a challenging year for the industry, but while many of our peers are merely weathering the storm, Gulfport remains solid — not only surviving this cyclical industry, but thriving during all seasons of the commodity price cycle.

Operationally, during 2015 production tracked well ahead of expectations and we continue to identify efficiencies and discover ways to deliver more with less. Furthermore, we have secured a large position in the core of a world-class asset, the Utica Shale, where we were the second-largest producer at year-end 2015.

This is a difficult time for many energy companies, but Gulfport has differentiated itself to not only weather these cycles but navigate them opportunistically and positioned itself, ultimately, to exit in a position of strength.

“We have spent the past decade and a half thoughtfully and strategically building a business that supports return-based investments. Gulfport has been cycle-tested before and proved to be stronger during those times. I expect this time will prove no different.”

CEO and President Michael G. Moore

Gulfport Energy Corporation is an Oklahoma City-based independent oil and natural gas exploration and production company with its principal producing properties located in the Utica Shale of Eastern Ohio and along the Louisiana Gulf Coast. In addition, Gulfport holds a sizeable acreage position in the Alberta Oil Sands in Canada through its 25% interest in Grizzly Oil Sands ULC.

March 23, 2016

DEAR FELLOW STOCKHOLDERS,

In spite of a difficult commodity environment for the energy sector, 2015 was another noteworthy year for Gulfport.



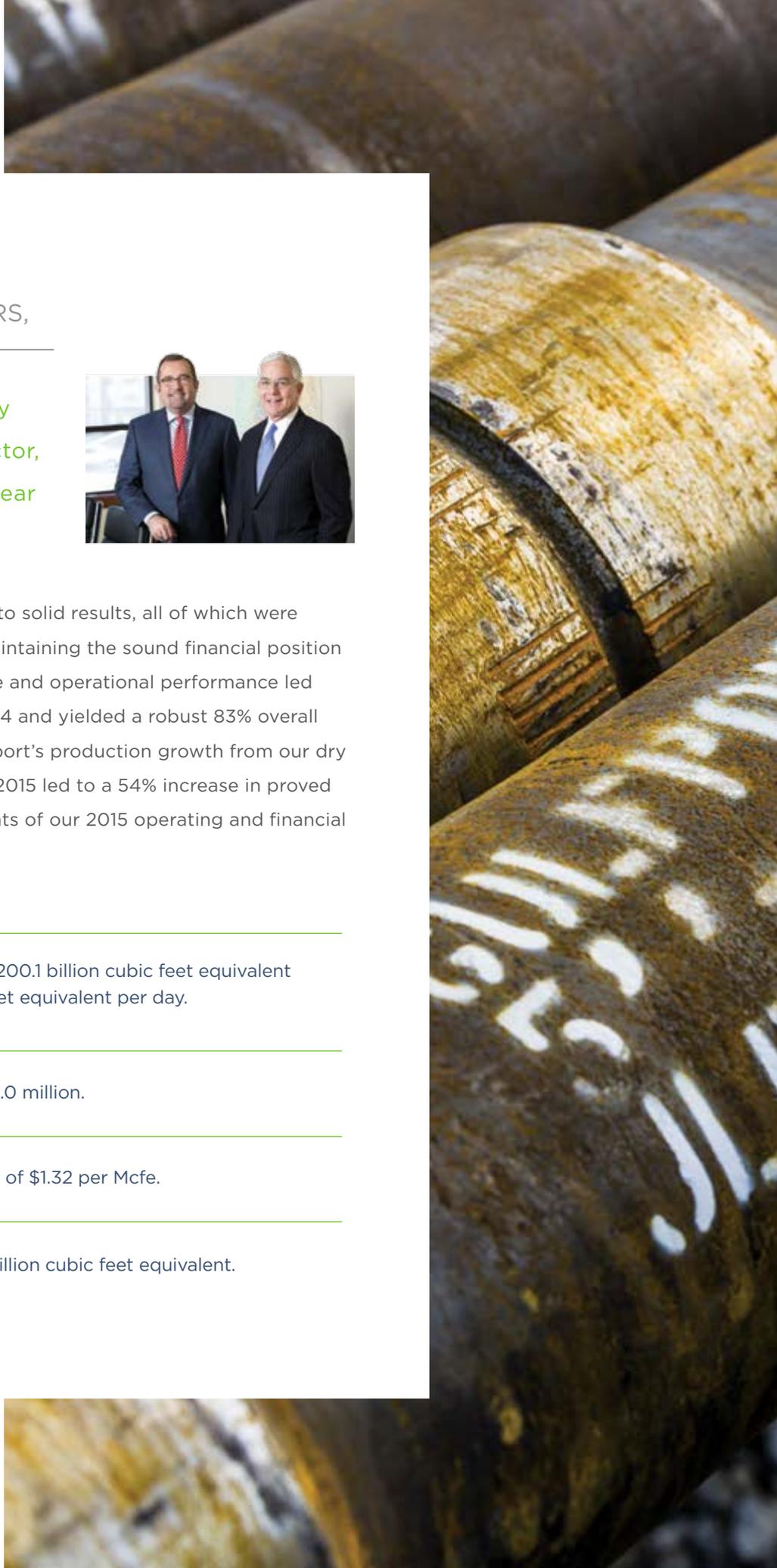
Our prudent planning for the year led to solid results, all of which were accomplished while protecting and maintaining the sound financial position of our Company. Our strong asset base and operational performance led to production growth of 128% over 2014 and yielded a robust 83% overall increase in total proved reserves. Gulfport's production growth from our dry gas position in the Utica Shale during 2015 led to a 54% increase in proved developed reserves alone. Key highlights of our 2015 operating and financial results include:

Total 2015 net production of 200.1 billion cubic feet equivalent or 548,188 thousand cubic feet equivalent per day.

Oil and gas revenues of \$709.0 million.

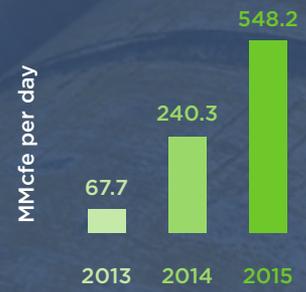
Total per unit operating costs of \$1.32 per Mcfe.

Total proved reserves of 1.7 trillion cubic feet equivalent.



PRODUCTION HIGHLIGHTS

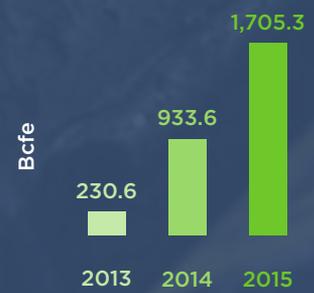
TOTAL NET PRODUCTION



2015 PRODUCTION MIX



TOTAL NET PROVED RESERVES

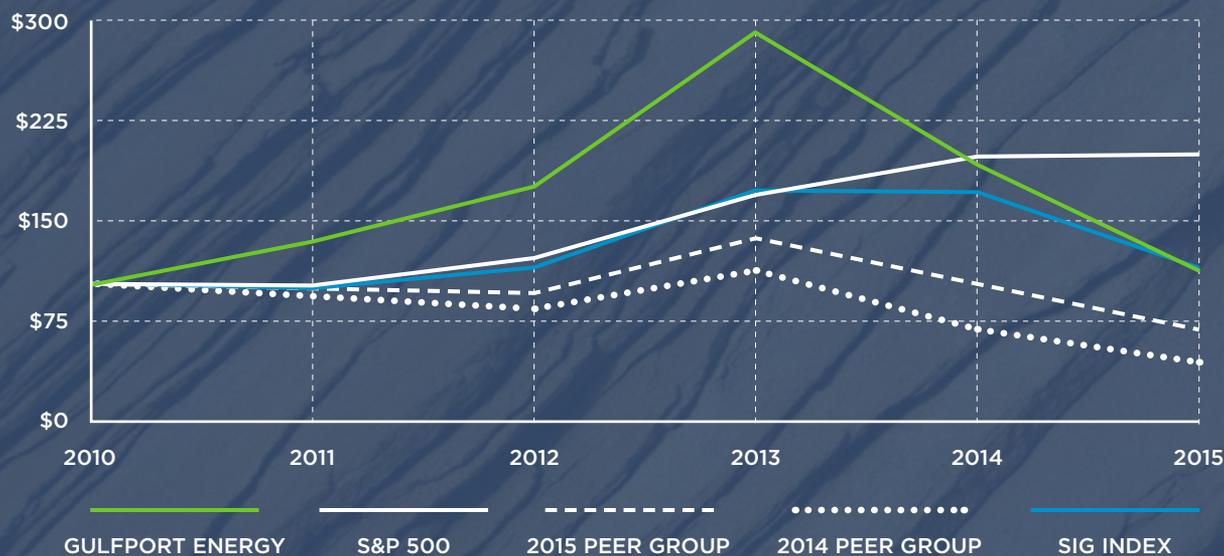


ON SOLID ROCK

As we expected, our strong balance sheet and continued operational execution led to opportunities to expand our core position in the Utica, and during 2015 we completed two pivotal acquisitions adding approximately 59,000 net acres in the prolific dry gas window of the play. Today, our acreage position in the Utica Shale totals approximately 237,000 net acres, providing Gulfport with a substantial level of inventory to support decades of activity in the basin.

During 2015, we were highly focused on identifying efficiencies and finding ways to deliver more with less. We leveraged the lower commodity price environment to gain access to higher-quality equipment and superior services, which led to dramatically increased productivity in our operations. On the drilling front, Gulfport ran an average of 3.7 rigs on our Utica Shale position and spud approximately 49 gross wells on our acreage. In addition, we turned to sales approximately 55 gross

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN



The graph and table below represent the Company's cumulative total return relative to the performance of its peers during the period from 12/31/2010 through 12/31/2015. The graph assumes \$100 invested at the closing price of the Company's common stock and that all dividends were reinvested on the date paid. The points on the graph represent fiscal year-end amounts based on the last trading day in each fiscal year.

- 2015 peer group includes AR, CLR, CNX, CRZO, EGN, FANG, GPOR, HK, LPI, MTDR, OAS, PDCE, RICE, RRC, SM, XEC.
- 2014 peer group includes CRZO, DNR, EGN, LPI, NFX, OAS, PDCE, QEP, RRC, ROSE, SD, SM, UPL, WLL, WPX.



wells in the play, bringing Gulfport's total wells producing in the Utica Shale at year-end 2015 to 165 gross wells. On the cost side, our heightened focus on efficiencies throughout the year led to cost reductions across all areas of the business. Gulfport's per unit operating cost, including LOE, production tax, midstream gathering and processing, and G&A, trended lower throughout the year, decreasing 35% over 2014 and exiting the year at approximately \$1.19 per Mcfe. In addition, we substantially reduced our drilling and completion costs per lateral foot by approximately 20%, firmly establishing Gulfport as a low-cost leader in the basin with regard to well costs.

On the midstream front, we continue to be pleased with the work of our third-party midstream providers, MarkWest Energy Partners and Rice Midstream Holdings LLC, and their ability to provide timely and reliable arrangements for the movement of our molecules to quality end markets. While the midstream buildout in the Utica Shale has certainly progressed rapidly, perhaps faster than any other new, emerging shale play in the U.S., our midstream relationships have and will continue to play an integral role in our operations, were key in supporting our growth during 2015 and will be critical as we continue to build on this growth for many years to come. In addition, during 2015 we announced that Gulfport and Rice Midstream Holdings LLC were

forming a joint venture to develop midstream assets to support our development, and potentially that of additional third-party operators, in Belmont, Jefferson and Monroe counties. Gulfport has a long history with Rice Energy under a joint development agreement entered into in October 2013, and we believe the new joint venture creates enhanced alignment with our midstream provider, providing increased certainty to timing of infrastructure buildout and further predictability to Gulfport's production profile. With regard to takeaway, to further support our growth and price realizations, we have taken a balanced approach to our firm marketing portfolio, providing us with the near-term ability to move molecules out of the basin to diverse premium markets and have the long-term flexibility to adjust activity as needed. We were mindful to right-size the portfolio and, to date, Gulfport has secured approximately 1.2 BBtu per day of firm arrangements to support our anticipated production growth and provide access to more favorably priced markets, including the Dawn market in Canada and the Midwest and Gulf Coast regions of the United States.

“Our 2015 results continue to be a testament to the quality of resource we have in the Utica Shale.”

UTICA SHALE

The Utica Shale is located in the Appalachian Basin of the United States and Canada. Comprised of organic rich calcareous black shale that was deposited about 440 million to 460 million years ago during the late Ordovician period, the Utica Shale overlies the Trenton limestone and is located a few thousand feet below the Marcellus Shale.

- Gulfport has approximately 237,000 net acres under lease in the Utica Shale and reported strong year-end 06
- production of approximately 623.7 MMcfepd during the fourth quarter of 2015, an increase of 76% over the fourth quarter of 2014. Gulfport's production growth during 2015, driven by the solid results from the dry gas phase windows of the play, led to an 86% increase in proved reserves over our 2014 report in the Utica Shale, totaling approximately 1.7 net Tcfe at year-end 2015. The Utica continues to prove itself an exceptional resource and Gulfport continues to believe the Utica Shale generates some of the lowest-cost molecules of natural gas in North America.



YEAR-END 2015 UTICA SHALE PRODUCTION STATS



LEASEHOLD POSITION

237,000

NET ACRES

PROVED RESERVES

1.7

NET TCFE

PRODUCTION

623.7

NET MMCFEPD

WELLS PRODUCING

165

GROSS

A full-page photograph of an industrial worker in a hard hat and safety gear operating machinery on a site. The worker is in the foreground, focused on a task. The background shows complex industrial structures and equipment under a clear sky. A dark blue semi-transparent box is overlaid on the left side of the image, containing white and green text.

“While we certainly cannot ignore the commodity environment we face today, we feel the highest value proposition for our shareholders in 2016 and beyond is a balanced approach.”

—
08
—

CEO and President Michael G. Moore



PREPARED FOR THE FUTURE

Our 2015 results are a testament to the quality of the resource we have in the Utica Shale, a basin that we believe generates some of the lowest-cost molecules of natural gas in North America. I would like to applaud the Gulfport team on its ability to remain nimble as we navigated 2015 and its dedication to executing on a program that enabled us to maintain a sound financial structure, which has positioned us well as we enter what looks to be another challenging year for the energy sector.

For 2016, our core philosophy stays the same and we continue to be dedicated to capital discipline, conservative leverage and creating long-term value for our stockholders. As we contemplated appropriate levels of activity for 2016, our focus was devoted towards developing a program that was efficient with our available capital while maintaining reasonable leverage metrics. Based on our current 2016 capital budget, we believe our high-quality asset base in the Utica will benefit from our solid hedge position and allow us to deliver an attractive rate of return, while growing production not only year-over-year, but also exit-to-exit, leaving the Company well-positioned as we enter 2017.

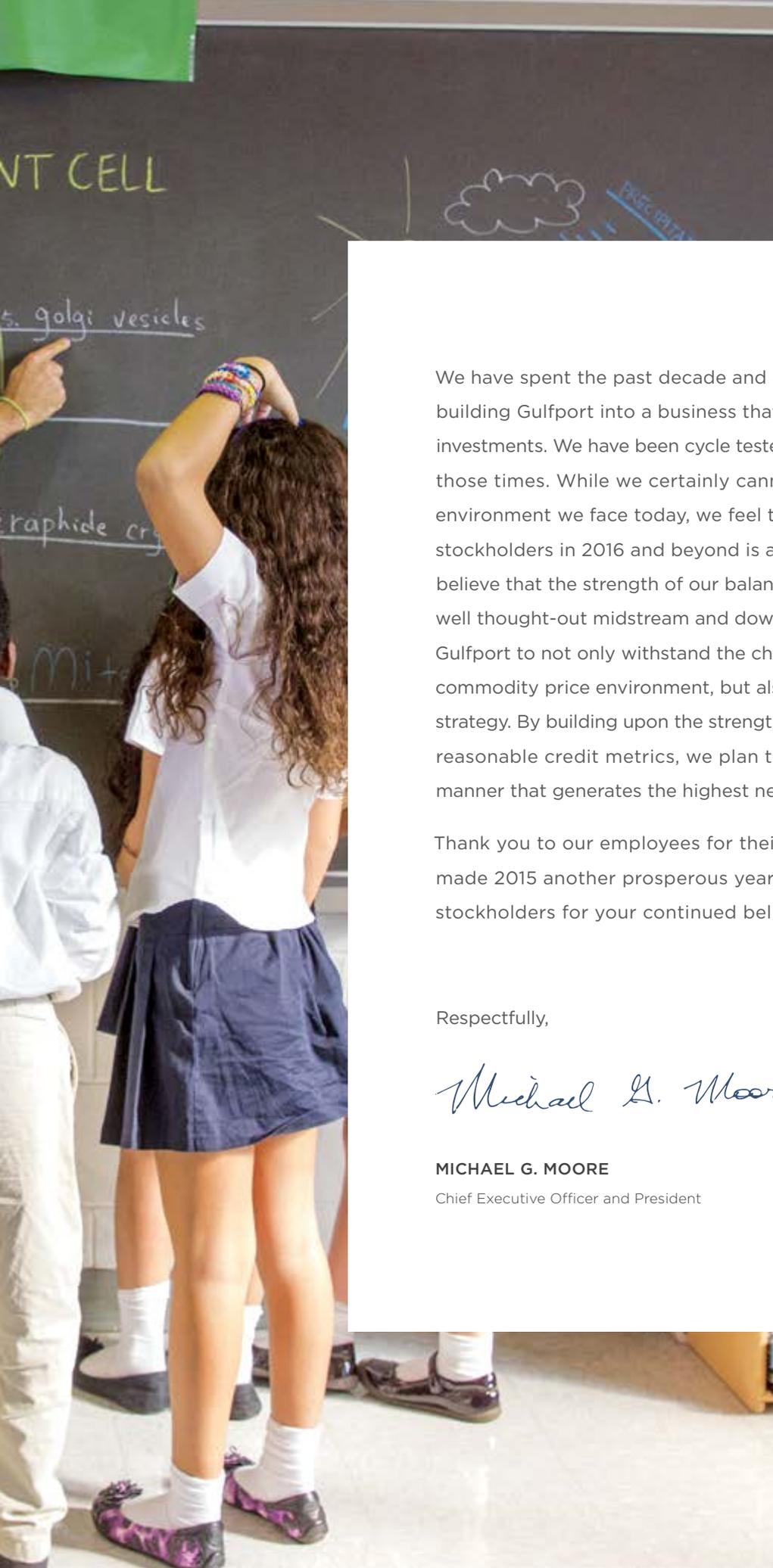
CORPORATE GIVING

Gulfport Energy Corporation is a value-driven, growth-oriented oil and gas exploration and production company committed to investing in the economic and social well-being of the communities where we operate. Our business' success correlates with the well-being of the communities where we reside and operate, which is why we are embracing our responsibility to advance the quality of life in these regions.

In Ohio, we created the Gulfport Energy Fund within the Foundation for Appalachian Ohio to support nonprofits, schools and communities in projects that — increase quality of life, create access to opportunities — or identify and implement a solution for a community need in the counties where Gulfport Energy operates. The Gulfport Energy Fund serves as an active source of support in Belmont, Guernsey, Harrison, Monroe, Jefferson and Noble counties in Ohio. We have already extended a helping hand to over 15,000 people, and we feel that we can truly make a difference for many years to follow.

In Oklahoma and Louisiana, we support projects, activities and programs benefiting and involving local community members. Through non-profit organizations, community organizations and schools, Gulfport is able to give back to the community in hopes of helping those around us. Our dedication to helping others goes beyond donations and volunteer hours — Gulfport strives to be the corporate citizen you can count on.





We have spent the past decade and a half thoughtfully and strategically building Gulfport into a business that supports sustainable, return-based investments. We have been cycle tested before and grew stronger during those times. While we certainly cannot ignore the commodity price environment we face today, we feel the highest value proposition for our stockholders in 2016 and beyond is a balanced approach. We continue to believe that the strength of our balance sheet, our hedge portfolio and our well thought-out midstream and downstream strategy uniquely positions Gulfport to not only withstand the challenges associated with the current commodity price environment, but also efficiently execute our development strategy. By building upon the strength of our balance sheet while maintaining reasonable credit metrics, we plan to develop this asset in a thoughtful manner that generates the highest net asset value for our stockholders.

Thank you to our employees for their dedication and hard work, which made 2015 another prosperous year for Gulfport and thank you to our stockholders for your continued belief in our company and its future.

Respectfully,

Michael G. Moore

MICHAEL G. MOORE

Chief Executive Officer and President

FINANCIAL HIGHLIGHTS

	2015	2014	2013
PRODUCTION			
Oil and Gas Volumes			
Natural gas (MMCF)	156,151	59,318	8,891
Oil (MBBLS)	2,899	2,684	2,317
Natural gas liquids (MGALS)	185,792	86,092	13,417
MMCFE	200,089	87,719	24,709
MCFEPD	548,188	240,327	67,695

INCOME STATEMENT

Revenues (in thousands)

Natural gas	\$ 507,726	\$ 329,254	\$ 21,015
Oil	\$ 141,816	\$ 247,381	\$ 224,129
Natural gas liquids	\$ 59,448	\$ 94,127	\$ 17,081
Other income (expense)	\$ 485	\$ 504	\$ 528
Total	\$ 709,475	\$ 671,266	\$ 262,753

Costs and Expenses (per MCFE)

Lease operating expenses	\$ 0.35	\$ 0.59	\$ 1.08
Production taxes	\$ 0.07	\$ 0.27	\$ 1.09
Midstream processing and marketing	\$ 0.69	\$ 0.73	\$ 0.45
General and administrative	\$ 0.21	\$ 0.44	\$ 0.91
Interest	\$ 0.26	\$ 0.27	\$ 0.71
Depreciation, depletion and amortization	\$ 1.69	\$ 3.03	\$ 4.81

Financial Highlights (in thousands, except per share data)

Net (loss) income	\$ (1,224,884)	\$ 247,403	\$ 153,192
Basic net (loss) income per share	\$ (12.27)	\$ 2.90	\$ 1.98
Diluted net (loss) income per share	\$ (12.27)	\$ 2.88	\$ 1.97
Basic weighted average shares outstanding	99,792	85,446	77,376
Diluted weighted average shares outstanding	99,792	85,813	77,862
EBITDA	\$ 349,268	\$ 690,922	\$ 388,415
Total assets	\$ 3,334,734	\$ 3,619,473	\$ 2,685,039
Total debt, including current maturity	\$ 946,263	\$ 703,564	\$ 291,090
Stockholders' equity	\$ 2,038,837	\$ 2,296,296	\$ 2,050,238

RESERVES

Proved Reserves

Natural gas (BCF)	1,560.1	719.0	146.4
Oil (MMBBL)	6.5	9.5	8.3
Natural gas liquids (MMBL)	17.7	26.3	5.7
Gas equivalent (BCFE)	1,705.3	933.6	230.6

FORM

10-K

2015

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, 2015
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, 2015, based on the closing price of the common stock on the NASDAQ Global Select Market on June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter (\$40.25 per share), was \$4,355,210,235.

As of February 10, 2016, 108,324,750 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation's Proxy Statement for the 2016 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

**GULFPORT ENERGY CORPORATION
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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 Item 1A. “*Risk Factors*” and Item 7. “*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 an interest in 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 an interest in an entity that operates in the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

As of February 10, 2016, we held leasehold interests in approximately 244,000 gross (237,000 net) acres in the Utica Shale primarily in Eastern Ohio, including approximately 24,000 net acres acquired in our purchase of Paloma Partners III, LLC, or Paloma, and approximately 35,000 net acres acquired from American Energy-Utica, LLC (now known as Ascent Resources Utica, LLC), or AEU, in each case during the second quarter of 2015. We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of December 31, 2015, had spud 219 gross wells (including wells from our AEU acquisition), 165 of which were completed and were producing. In 2015, we spud 49 gross (38.4 net) wells, of which ten were completed as producing wells, 36 were in various stages of completion and, as of December 31, 2015, three were still being drilled. We commenced sales from 55 gross wells (50.2 net wells) in the Utica Shale during 2015. During 2016 (through February 10, 2016), we had spud four gross (2.2 net) wells. As of February 10, 2016, one well was waiting on completion and three were still drilling. In addition, 25 gross (7.3 net) wells were drilled by other operators on our Utica Shale acreage during 2015.

We currently intend to drill 29 to 32 gross (19 to 21 net) horizontal wells, and commence sales from 44 to 48 gross (28 to 30 net) horizontal wells on our Utica Shale acreage in 2016 for an estimated aggregate cost of \$219.0 million to \$247.0 million. We currently anticipate 17 to 19 gross (two to three net) horizontal wells will be drilled, and sales commenced from 30 to 34 gross (eight to nine net) horizontal wells, by other operators on our Utica Shale acreage during 2016 for an estimated net cost to us of \$90.0 million to \$100.0 million.

Aggregate net production from our Utica Shale acreage during the three months ended December 31, 2015 was approximately 57,381 net million cubic feet of natural gas equivalent, or MMcfe, or 623.7 MMcfe per day, of which 85% was from natural gas and 15% was from oil and natural gas liquids, or NGLs. During January 2016, our average daily net production from the Utica Shale was approximately 586.9 MMcfe, of which 86% was from natural gas and 14% was from oil and NGLs.

In 2015, at our WCBB field, we recompleted 35 gross and net wells and spud no new wells. In the fourth quarter of 2015, production at WCBB was approximately 1,363 MMcfe, or an average of 14.8 MMcfe per day, of which 97% was from oil and 3% was from natural gas. During January 2016, our average net daily production at WCBB was approximately 13.1 MMcfe, 100% of which was from oil.

In 2015, at our East Hackberry field, we recompleted 37 gross and net wells and spud no new wells. In the fourth quarter of 2015, net production at East Hackberry was approximately 315.8 MMcfe, or an average of 3.4 MMcfe per day, of which 94% was from oil and 6% was from natural gas. During January 2016, our average net daily production at East Hackberry was approximately 4.6 MMcfe, of which 96% was from oil and 4% was from natural gas.

In 2015, at our West Hackberry field, we had no recompletions and spud no new wells. In the fourth quarter of 2015, net production at West Hackberry was approximately 45.1 MMcfe, or an average of 489.9 Mcfe per day, of which 94% was from oil and 6% was from natural gas. During January 2016, our average net daily production at West Hackberry was approximately 685.5 Mcfe, of which 99% was from oil and 1% was from natural gas.

We currently estimate our 2016 activities in our Southern Louisiana fields to be approximately \$26.0 million to \$28.0 million in aggregate for maintenance capital activities.

As of December 31, 2015, we held leasehold interests in approximately 5,000 net acres in the Niobrara Formation in Northwestern Colorado. During the year ended December 31, 2015, there were no wells spud on our Niobrara Formation acreage. In the fourth quarter of 2015, net production from our Niobrara Formation acreage was approximately 29.1 MMcfe, or an average of 315.9 Mcfe per day, 100% of which was from oil. During January 2016, our average net daily production from our Niobrara Formation acreage was approximately 292.5 Mcfe, 100% of which was from oil. During 2016, we currently do not anticipate drilling any wells in the Niobrara Formation.

As of December 31, 2015, we held leasehold interests in approximately 864 net acres in the Bakken Formation of Western North Dakota and Eastern Montana, interests in 18 wells and overriding royalty interests in certain existing and future wells. In the fourth quarter of 2015, our net production from this acreage was approximately 94.3 MMcfe, or an average of 1.0 MMcfe per day, of which 90% was from oil and natural gas liquids and 10% was from natural gas. During January 2016, our average daily net production from our Bakken Formation acreage was approximately 375.0 Mcfe, of which 82% was from oil and 18% was from natural gas.

We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. As of December 31, 2015, Grizzly had approximately 830,000 net acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. For additional information regarding Grizzly, see “*Our Equity Investments - Grizzly Oil Sands*” below.

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. For additional information regarding Tatex II and our other activities in Southeast Asia, see “*Our Equity Investments - Thailand*” below.

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. For additional information regarding these entities, see “*Our Equity Investments - Other Investments*” below.

As of December 31, 2015, we had 1.7 Tcfe of proved reserves with a present value of estimated future net revenues, discounted at 10%, or PV-10, of approximately \$765.8 million and associated standardized measure of discounted future net cash flows of approximately \$764.3 million, 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 (the most directly comparable GAAP measure) to PV-10.

Principal Oil and Natural Gas Properties

The following table presents certain information as of December 31, 2015 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)	39.11/48.15	306	147.49	3	2.66	36,549	32,110	1,558,677	3,618
West Cote Blanche Bay Field (5)	80.108/100	98	98	202	202	5,668	5,668	894	2,258	—	14,442
E. Hackberry Field (6)	79.91/100	21	21	124	124	2,910	2,910	316	309	—	2,168
W. Hackberry Field	80.00/100	5	5	8	8	1,192	1,192	—	14	—	88
Niobrara Formation	38.94/46.77	4	2	2	1	2,740	1,370	55	117	—	758
Bakken Formation	1.51/1.83	18	0.3	—	—	1,861	163	189	141	—	1,038
Overrides/Royalty Non-operated	Various	541	0.71	—	—	—	—	14	1	—	23
Total		993	274.5	339	337.66	50,920	43,413	1,560,145	6,458	17,736	1,705,312

(1) Net Revenue Interest (NRI)/Working Interest (WI) for producing wells.

(2) Includes two gross and net wells at WCBB that are producing intermittently.

(3) Developed acres are acres spaced or assigned to productive wells. Approximately 17% 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 141 gross (15.66 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, 2015, we held leasehold interests in approximately 240,000 gross (234,000 net) acres in the Utica Shale.

Area History

The Ohio Department of Natural Resources reported that in the Utica Shale in Ohio, as of January 2, 2016, there were 1,126 producing horizontal wells, 403 horizontal wells that had been drilled but were not yet completed or connected to a pipeline, 12 horizontal wells that were being drilled and an additional 447 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 natural 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, 2015, had spud 219 gross wells (including wells from our AEU acquisition), 165 of which were completed and were producing. In 2015, we spud 49 gross (38.4 net) wells, of which ten were completed as producing wells, 36 were in various stages of completion and, as of December 31, 2015, three were still being drilled. We commenced sales from 55 gross wells (50.2 net wells) in the Utica Shale during 2015. During 2016 (through February 10, 2016), we had spud four gross (2.2 net) wells of which one was waiting on completion and three were still drilling. In addition, 25 gross (7.3 net) wells were drilled by other operators on our Utica Shale acreage during 2015.

We currently intend to drill 29 to 32 gross (19 to 21 net) horizontal wells, and commence sales from 44 to 48 gross (28 to 30 net) horizontal wells, on our Utica Shale acreage in 2016 for an estimated aggregate cost of \$219.0 million to \$247.0 million. We currently anticipate 17 to 19 gross (two to three net) horizontal wells will be drilled, and sales commenced from 30 to 34 gross (eight to nine net) horizontal wells, by other operators on our Utica Shale acreage during 2016 for an estimated net cost to us of \$90.0 million to \$100.0 million. As of February 10, 2016, we had three operated horizontal rigs drilling in the play.

Production Status

Aggregate net production from our Utica Shale acreage during the three months ended December 31, 2015 was approximately 57,381 MMcfe, or 623.7 MMcfe per day, of which 85% was from natural gas and 15% was from oil and NGLs. During January 2016, our average daily net production from the Utica Shale was approximately 586.9 MMcfe, of which 86% was from natural gas and 14% was from oil and NGLs. The slight decrease in January 2016 production was the result of our decision to temporarily curtail our production beginning in the fourth quarter of 2015.

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, 2015, 973 were completed as producing wells. From the date of our acquisition of WCBB in 1997 through December 31, 2015, we drilled 265 new wells, 233 of which were productive, for an 88% success rate. As of December 31, 2015, estimated field cumulative gross production was 197.9 MMBO and 237.1 Bcf of gas. Of the 1,077 wells drilled in WCBB as of December 31, 2015, 96 were producing, 202 were shut-in, two were producing intermittently, and six were being used as salt water disposal wells. The other 771 wells have been plugged and abandoned.

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, 2015, 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, seven natural gas compressors, a storage barge facility, a dock, a dehydration unit and a salt water disposal system.

Recent Activity

In 2015, at our WCBB field, we recompleted 35 gross and net wells and spud no new wells. As of February 10, 2016, we had recompleted six gross and net wells during 2016 in our WCBB field.

Production Status

In the fourth quarter of 2015, our net production at WCBB was approximately 1,363 MMcfe, or an average of 14.8 MMcfe per day, of which 97% was from oil and 3% was from natural gas. During January 2016, our average net daily production at WCBB was approximately 13.1 MMcfe, 100% of which was from oil. The slight decrease in average net daily production in January 2016 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 79.91% average NRI) in certain producing oil and natural gas properties situated in the East Hackberry field. As of December 31, 2015, we held beneficial interests in approximately 4,116 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 2015 was over 4,425 MBO and 331.9 Bcf of casinghead gas production. A total of 269 wells have been drilled on our portion of the field. As of December 31, 2015, 21 wells had daily production, 125 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, three natural gas compressors, dehydration units and salt water disposal systems.

Recent Activity

During 2015 at East Hackberry, we recompleted 37 gross and net wells and spud no new wells. As of February 10, 2016, we had recompleted two gross and net wells during 2016 in our East Hackberry field.

Production Status

In the fourth quarter of 2015, our net production at East Hackberry was approximately 315.8 MMcfe, or an average of 3.4 MMcfe per day, of which 94% was from oil and 6% was from natural gas. During January 2016,

our average net daily production at East Hackberry was approximately 4.6 MMcfe, of which 96% was from oil and 4% was from natural gas. The slight increase in production in January 2016 is a result of our 2016 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 80.00% 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 2015 was 452 MBO and 140 Bcf of natural gas. As of December 31, 2015, 41 wells had been drilled on our portion of West Hackberry. As of December 31, 2015, five of such wells were producing, eight 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 Activity

During 2015 at West Hackberry, we had no recompletions and spud no new wells. We do not anticipate drilling any wells in our West Hackberry field during 2016.

Production Status

In the fourth quarter of 2015, our net production at West Hackberry was approximately 45.1 MMcfe, or an average of 489.9 Mcfe per day, of which 94% was from oil and 6% was from natural gas. During January 2016, our average net daily production at West Hackberry was approximately 685.5 Mcfe, of which 99% was from oil and 1% 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, 2015, we held leases for approximately 5,000 net acres. In 2015, 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 2015, net production from our Niobrara Formation acreage was approximately 29.1 MMcfe, or an average of 315.9 Mcfe per day, 100% of which was from oil. During January 2016, our average net daily production from our Niobrara Formation acreage was approximately 292.5 Mcfe, 100% of which was from oil.

Facilities

There are typical land oil and natural 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 Activity

There were no new wells drilled on our Niobrara Formation acreage in 2015. We do not anticipate drilling any wells in the Niobrara Formation during 2016.

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, 2015, we held approximately 864 net acres, interests in 18 wells and overriding royalty interests in certain existing and future wells.

Production Status

In the fourth quarter of 2015, our net production from this acreage was approximately 94.3 MMcfe, or an average of 1.0 MMcfe per day, of which 90% was from oil and natural gas liquids and 10% was from natural gas. During January 2016, our average daily net production from our Bakken Formation acreage was approximately 375.0 Mcfe, of which 82% was from oil and 18% was from natural gas.

Facilities

There are typical land, oil and natural 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 Activities

There were no new wells drilled on our Bakken Formation acreage in 2015. We do not anticipate drilling any wells in the Bakken Formation during 2016.

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, 2015:

<u>Field</u>	<u>State</u>	<u>Parish/County</u>	<u>Acreage Working Interest</u>	<u>Overriding Royalty Interests</u>	<u>Producing Wells</u>	<u>Non-Producing Wells</u>
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	0.13%	—	1	—
Watonga Chickasha Trend	Oklahoma	Canadian	0.052%	—	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, 2015, 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 900 barrels of bitumen per day at its Algar Lake SAGD project during the first quarter of 2015. In April 2015, Grizzly determined to cease bitumen production at its Algar Lake facility due to the level of commodity prices. Grizzly continues to monitor market conditions as it assesses future plans for the facility. We reviewed our investment in Grizzly at September 30, 2015 and December 31, 2015 for impairment, resulting in an aggregate other than temporary impairment write down of \$101.6 million for the year ended December 31, 2015. If commodity prices continue to decline, further impairment of our investment in Grizzly may result in the future. 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 early 2016. 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. In December 2015, Grizzly suspended the review of the Thickwood application by the AER. The Thickwood application will be resubmitted once the regulations have been updated. Grizzly has also developed delineation drilling, seismic and regulatory work plans at its Cadotte, Peace River

property. Grizzly has pursued 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 II. Tatex 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. Tatex II accounts for its investment in APICO using the cost method. In December 2006, first gas sales were achieved at the Phu Horm field located in northeast Thailand. Phu Horm's initial gross production was approximately 60 million cubic feet per day. For 2015, net gas production was approximately 90 MMcf per day and condensate production was 407 barrels per day. Hess Corporation, or Hess, operates the field with a 35% interest. Other interest owners include APICO (35% interest), PTT Exploration and Production Public Company Limited (20% interest) and ExxonMobil (10% interest). Our gross working interest (through Tatex II as a member of APICO) in the Phu Horm field is 0.7%. Since our ownership in the Phu Horm field is indirect and Tatex II's investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information.

We 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 this concession. Each of the wells lacked sufficient permeability to produce in commercial quantities. Tatex III allowed the concession to expire in January 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 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 its proposed initial public offering. Mammoth originally intended to pursue the offering in 2015; however, Mammoth continues to evaluate market conditions and the commodity price environment which will impact the timing of the proposed offering. See Note 4 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments.

In February 2016, we entered into a joint venture with Rice Midstream Holdings LLC, or Rice, a subsidiary of Rice Energy Inc., to develop natural gas gathering assets in eastern Belmont County and Monroe County,

Ohio, which we refer to as the dedicated areas. We own a 25% interest in the joint venture and Rice acts as operator and owns the remaining 75% interest in the joint venture. Construction of the gathering assets, which is underway, is expected to provide connectivity of our dry gas gathering systems and interchangeability of natural gas across our firm portfolio. The joint venture has completed the first phase of the projects: a lateral that connects two existing dry gas gathering systems on which we currently flow the majority of our dry gas volumes. The lateral has been commissioned and first flow commenced on February 1, 2016. In addition, we and Rice have agreed to negotiate in good faith to expand the joint venture to provide water services to us within the dedicated areas.

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. The majority of our Utica Shale oil is sold to Shell and Marathon Petroleum Corporation, or Marathon. The purchaser takes custody at the MarkWest Utica EMG, or MarkWest, operated condensate stabilizer located near Cadiz, Ohio. Our Utica Shale NGLs are currently purchased by MarkWest which remits to us a weighted average selling price of products sold to various markets. We have NAESBs in place with various purchasers for our Utica Shale natural gas production. The majority of our gas is sold to BP Energy Company, or BP. In 2015, 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 or at central delivery points 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, 2015, we sold approximately 90% and 10% of our oil production to Shell and Marathon Oil Corporation, respectively, 76% and 24% of our natural gas liquids production to MarkWest and Antero Resources, respectively and 79%, 14% and 5% of our natural gas production to BP, DTE Energy Trading, Inc. and Hess, respectively. 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 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 and 32%, 31% and 17% of our natural gas production to Sequent Energy Management, L.P., Hess and Interstate Gas Supply, Inc., respectively.

As of December 31, 2015, we had an average of approximately 476,000 MMBtu per day of firm sales contracted with third parties for 2016. We had an average of approximately 349,000 MMBtu per day, 216,000 MMBtu per day, 197,000 MMBtu per day, 152,000 MMBtu per day and 62,000 MMBtu per day contracted with third parties for 2017, 2018, 2019, 2020 and thereafter, respectively.

Transportation and Takeaway Capacity

In Ohio, as of December 31, 2015, we had entered into firm transportation contracts to deliver approximately 725,000 MMBtu to 775,000 MMBtu per day for 2016. For 2017, we had entered into firm transportation contracts to deliver approximately 775,000 MMBtu to 1,125,000 MMBtu per day. For 2018 through 2020, we had entered into firm transportation contracts to deliver approximately 1,125,000 MMBtu per day. 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 2016. Our primary long-haul firm transportation commitments include the following:

- 520,000 MMBtu per day of firm capacity on Dominion East Ohio, which began in 2014 and allows us to reach additional connectivity to Gulf Coast and Midwest natural gas markets;
- 250,000 MMBtu per day of firm capacity on Dominion Transmission, which began in 2015 and allows us to reach additional connectivity to Midwest natural gas markets;
- 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, which began in 2015 and allows us to reach Gulf Coast delivery points;
- 275,000 MMBtu per day of firm capacity on Rockies Express Pipeline facilities, which began in 2015 and allows us to reach additional connectivity to Gulf Coast and Midwest markets;
- 50,000 MMBtu per day of firm capacity on Rockies Express Pipeline facilities expected to begin in 2016 allowing additional connectivity to Gulf Coast and Midwest markets;
- 20,000 MMBtu per day of firm capacity on Natural Gas Pipeline facilities which began in 2015 and allows us to reach 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;
- 54,000 MMBtu per day of firm capacity on Texas Gas Transmission facilities expected to begin in 2017 allowing additional access to Gulf Coast delivery points;
- 100,000 MMBtu per day of firm capacity on Texas Eastern Transmission facilities expected to begin in 2017 allowing additional access to Midwest delivery points;
- 150,000 MMBtu per day of firm capacity on Energy Transfer's Rover Pipeline facilities expected to begin in 2017 allowing additional access to Canadian, Midwest and Gulf Coast delivery points; and
- 100,000 MMBtu per day of firm capacity on Columbia Gulf Transmission facilities expected to begin in late 2017 allowing additional access to 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 Oil and Natural Gas 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 or seismically sensitive areas, 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. Liability under such laws and regulations is strict (i.e., no showing of “fault” is required) and can be joint and several. 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. Moreover, the EPA or state or local governments may 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 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” are subject to strict liability that, in some circumstances, may be joint and several, 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 April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to publicly owned treatment works, or POTW, which regulations are discussed in more detail below under the caption “- *Regulation of Hydraulic Fracturing.*” 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 liability that, in some circumstances, may be joint and several 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 gases, 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 July 2010, 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 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 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. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

The EPA also adopted a GHG reporting rule in September 2009 authorizing the collection of GHG data from large emission sources across a range of industry sectors. In November 2010, the EPA expanded the GHG

reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

The EPA has continued to adopt GHG regulations applicable to other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the Clean Power Plan in the D.C. Circuit Court of Appeals. 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.

In December 2015, the United States joined the international community at the 21st Conference of the Parties, or COP-21, of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake “ambitious efforts” to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

Restrictions on emissions of methane or carbon dioxide that may be imposed 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, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While our business is not a party to this litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, 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 the Occupational Safety and Health Act, or 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. Furthermore, 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, have been proposed in recent sessions of Congress.

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 18, 2014. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism - regulatory, voluntary, or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures. Also, on April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to POTW. The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to a POTW. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

On August 16, 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. 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. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. For example, in September 2013 and December 2014, the EPA amended its rules to extend compliance deadlines and to clarify the NSP standards. Further, on July 31, 2015, the EPA finalized two updates to the NSP standards to address the definition of low-pressure wells and references to tanks that are connected to one another (referred to as connected in parallel). In addition, on September 18, 2015, the EPA published a suite of proposed rules to reduce methane and VOC emissions from oil and gas industry, including new "downstream" requirements covering equipment in the natural gas transmission segment of the industry that was not regulated by the 2012 rules. The public comment period closed on December 4, 2015. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

In addition, on March 26, 2015, the Bureau of Land Management, or BLM, published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. The rule took effect on June 24, 2015, although it is the subject of several pending lawsuits filed by industry groups and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. On September 30, 2015, the United States District Court for Wyoming issued a preliminary injunction preventing the BLM from implementing the rule nationwide. This order has been appealed to the Tenth Circuit Court of Appeals. Also, on January 22, 2016, the BLM announced a proposed rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The proposed rule would require operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule would also clarify when operators owe the government royalties for flared gas.

Furthermore, 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. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

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 OSHA, to state regulators and on a public internet website. 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. 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. RRC has used this authority to deny permits for waste disposal wells. Effective August 26, 2011, Montana adopted hydraulic fracturing well integrity and disclosure regulations under which well operators must demonstrate a suitable and safe mechanical configuration for the proposed stimulation treatment and provide information in the drilling permit application 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.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, 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 ratable production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and

abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

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

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 are provided on an open-access, non-discriminatory basis at cost-based rates or at negotiated rates. 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.

In July 2015, the Ohio Department of Natural Resources, or the ODNR, enacted a comprehensive set of rules to regulate the construction of well pads. Under these new rules, operators must submit detailed horizontal well pad site plans certified by a professional engineer for review by the ODNR Division of Oil and Gas Resources Management prior to the construction of a well pad. These rules will result in increased construction costs for operators. It is expected that the ODNR will pursue further initiatives in 2016, including additional emergency response rules.

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 \$40.0 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. All of our insurance coverage includes deductibles of up to \$250,000 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 2015 and 2014 were approximately \$0.1 million and \$0.2 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 26,900 square feet of office space in other buildings in Oklahoma City. A new corporate headquarters is currently under construction in Oklahoma City, Oklahoma. The building, currently scheduled to be completed in the fourth quarter of 2016, will have approximately 120,000 square feet of office space and will allow our employees to office in one location in Oklahoma City. We have received various offers to purchase or lease our existing headquarters building which we are evaluating.

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, 2015, we had 230 employees. An unrelated third-party Louisiana well servicing company provides a majority of the 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, have, and may continue to, 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 natural gas and, to a lesser extent, oil. 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;
- 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;
- the overall domestic and global economic environment; and
- weather conditions, including hurricanes, and other natural disasters that can affect oil and natural gas operations over a wide area.

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 \$27.56 per barrel, or Bbl, in January 2016 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 \$1.80 per MMBtu in December 2015 to a high of \$7.51 per MMBtu in January 2010. During 2015, WTI prices ranged from \$36.48 to \$65.69 per Bbl and the Henry Hub spot market price of natural gas ranged from \$1.80 to \$3.65 per MMBtu. On January 20, 2016, the WTI posted price for crude oil was \$28.35 per Bbl and the Henry Hub spot market price of natural gas was \$2.12 per MMBtu, representing decreases of 57% and 42%, respectively, from the high of \$65.69 per Bbl of oil and \$3.65 per MMBtu for natural gas during 2015. 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 further 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.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our future growth rate.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our 2016 business plan, we considered allocating capital and other resources to various aspects of our businesses, including well development, reserve acquisitions, midstream infrastructure and other activities. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2016 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, including the appropriate rate of reserve development, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2016 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

We periodically engage in acquisitions, dispositions and other strategic transactions, including equity investments and joint ventures such as our recent joint venture with Rice. These transactions involve various inherent risks, such as changes in prevailing market conditions, our ability to obtain the necessary regulatory approvals, the timing of and conditions that may be imposed on us by regulators and our ability to achieve benefits anticipated to result from the transactions. Further, our equity investments and joint venture arrangements may restrict our operational and corporate flexibility and subject us to risks and uncertainties, such as committing us to fund operating and/or capital expenditures, the timing and amount of which we may not be able to control. Further, the counterparties to these transactions may not satisfy their obligations to the joint venture. Our inability to complete a transaction or to achieve our strategic or financial goals in any transaction could have significant adverse effects on our earnings, cash flows and financial position.

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 and the European, Asian and the United States financial markets 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 further, 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, acquisition 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 2016 to be in the range of \$335.0 million to \$375.0 million and an additional \$60.0 million to \$65.0 million for acreage expenses, primarily lease extensions, in the Utica Shale and \$30.0 million to \$35.0 million for cash capital contributions to our midstream joint venture with Rice in Eastern Ohio.

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;
- our ability to acquire, locate and produce economically 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 2016 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 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, 2015, 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 900 barrels of bitumen per day at its Algar Lake SAGD project during the first quarter of 2015. In April 2015, Grizzly determined to cease bitumen production at its Algar Lake facility due to the level of commodity prices. Grizzly continues to monitor market conditions as it assesses future plans for the facility. We reviewed our investment in Grizzly at September 30, 2015 and December 31, 2015 for impairment, resulting in an aggregate other than temporary impairment write down of \$101.6 million for the year ended December 31, 2015. If commodity prices continue to decline, further impairment of our investment in Grizzly may result in the future. The Algar Lake and other pending and proposed projects are complex, subject to extensive governmental regulation and will require significant additional financing. There can be no assurance that the necessary governmental approvals will be granted or that such financing 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.

Oil and natural gas production operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Restrictions on the ability to obtain water may impact our operations.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our 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, or our other senior management and technical personnel, could disrupt our operations and have a material adverse effect on our financial condition and results of operations. 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 three of our 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) Netherland, Sewell & Associates, Inc., or NSAI, with respect to our Utica Shale acreage at December 31, 2015 and our WCBB, Hackberry and Niobrara fields at each of December 31, 2015, 2014 and 2013, (ii) Ryder Scott with respect to our Utica Shale acreage at December 31, 2014 and 2013 and (iii) our personnel with respect to our overriding royalty and non-operated interests at December 31, 2015, 2014 and 2013. 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 2015, 2014 and 2013 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, 2015, 2014 and 2013, 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 2015, 2014 and 2013 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, 2015, 2014 and 2013, respectively, in accordance with the revised guidelines of the SEC applicable to reserves estimates for such years. Commodity prices have deteriorated significantly since that time and, accordingly, using more recent prices in estimating our proved reserves, without giving effect to any acquisition or development activities we have executed during 2016, would result in a reduction in proved reserve volumes due to economic limits. Furthermore, any such reduction in proved reserve volumes combined with lower commodity prices would substantially reduce the PV-10 and standardized measure of discounted future net cash flows from our proved reserves as of a more recent date.

Actual future net revenues from our oil and natural gas properties will also 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, because they have become uneconomic or otherwise.

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

Approximately 55.0% of our total estimated proved reserves at December 31, 2015, 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, further decreases in commodity prices 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. With respect to our Utica Shale acreage where we are focusing substantially all 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. We are also at risk with respect to oil and natural gas produced at our Southern Louisiana fields. 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. 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 fields. 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.

If production from our Utica Shale acreage decreases due to decreased developmental activities, production related difficulties or otherwise, we may fail to meet our firm commitment delivery obligations under our firm transportation contracts, which will result in fees and may have a material adverse effect on our operations.

As of December 31, 2015, we had entered into firm transportation contracts to sell approximately 725,000 MMBtu to 775,000 MMBtu per day for 2016. For 2017, we had entered into firm transportation contracts to sell approximately 775,000 MMBtu to 1,125,000 MMBtu per day. For 2018 through 2020, we had entered into firm transportation contracts to sell approximately 1,125,000 MMBtu per day. See Item 1. “*Business-Transportation and Takeaway Capacity.*” Under these firm transportation contracts, we are obligated to deliver minimum daily volumes or pay fees for any deficiencies in deliveries. If production from our Utica Shale acreage decreases due to decreased developmental activities, taking into consideration the current low commodity price environment, production related difficulties or otherwise, we may be unable to meet our obligations under the existing firm transportation contracts, resulting in fees, which may be significant and may have a material adverse effect on our 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 Ohio, Louisiana 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, seismically active areas 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 or any potential future agreements, 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 have fulfilled our obligations under the compliance agreement and have been released from it by the Division. We cannot assure you that we will not be subject to compliance agreements with the Division or other regulatory bodies in the future. Our failure to

comply with any such compliance agreements may result in the suspension of all or part of drilling and production operations for some specified period as well as the imposition of 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 have been an early entrant into the Utica Shale in Eastern Ohio. We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012. As a developing play, our drilling results in this area are more uncertain than drilling results in areas that are more developed and have been producing for a longer period of time. 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.

A key 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. Approximately 24% of our total Utica Shale undeveloped acreage will be subject to expiration in 2016, with 9% of such acreage expiring in 2017, 18% in 2018, 1% in 2019 and 12% 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, 2015, leases representing 36%, 7%, 8% and 39%, respectively, of our total Niobrara Formation undeveloped acreage are scheduled to expire in 2016, 2017, 2018 and 2019. 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. If we are unable to fund renewals of expiring leases, we could lose portions of our acreage and 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.

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, including those 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 legislation and regulations of our industry 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 certain 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, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has in the past taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control, or UIC, program under the federal State Drinking Water Act, or the SDWA, specifically as “Class II” UIC wells. Furthermore, 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 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 EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism - regulatory, voluntary or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures. Also, on April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to publicly owned treatment works, or POTW. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to a POTW. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities and the environmental impacts of discharges from CWT facilities.

On August 16, 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. 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. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

Furthermore, 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 continues to evaluate the potential impacts of hydraulic fracturing on drinking water resources and the induced seismic activity from disposal wells and has recommended strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

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 federal, state and local laws and initiatives concerning hydraulic fracturing, see Item 1. "*Business - Regulation - Regulation of Hydraulic Fracturing*" above. 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, induced seismic activity, 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. Further, in February 2016, the Obama administration issued a proposed budget which includes, among other things, a proposed tax of \$10.25 per barrel equivalent on petroleum products.

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 have imposed a 6.5% tax on oil and gas sold at the wellhead. Although the severance tax increase was removed from the bill subsequently passed by the Ohio House, additional severance tax proposals are expected to be introduced in Ohio.

These proposed changes in the U.S. and applicable state tax law, if adopted, or other similar changes that tax our production or 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.

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 recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases, or GHGs. The EPA has finalized a series of GHG monitoring, reporting and emissions control rules for oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of GHGs primarily

through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. While we are subject to certain federal GHG monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives. For a description of GHG existing and proposed rules and regulations, see Item 1. “*Business - Regulation - Environmental Regulation - Climate Change.*”

In December 2015, the United States joined the international community at the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake “ambitious efforts” to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG 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.

In addition, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While our business is not a party to this litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

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 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 a 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. 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.

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.

We depend upon a limited number of customers for the sale of most of our oil and natural gas production. During the year ended December 31, 2015, we sold approximately 90% and 10% of our oil production to Shell and Marathon Oil Corporation, respectively, 76% and 24% of our natural gas liquids production to MarkWest and Antero Resources, respectively, and 79%, 14% and 5% of our natural gas production to BP, DTE Energy Trading, Inc. and Hess, respectively. 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. If a purchaser is unable to satisfy its contractual obligations, we may be unable to sell such production to other customers on terms we consider acceptable. Further, the inability of one or more of our customers to pay amounts owed to us could materially and adversely affect our business, financial condition, results of operations and cash flows.

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 2015, 2014 and 2013 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. As a result of the decline in commodity prices, we recognized a ceiling test impairment of \$1.4 billion for the year ended December 31, 2015. If prices of oil, natural gas and natural gas liquids continue to decrease, we may be required to further write down the value of our oil and natural 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 2016 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 information regarding these fixed price swaps, see Item 7A. “Quantitative and Qualitative Disclosures about Market Risk.” 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, whether due to cyber attack or otherwise, 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.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and processing activities. For example, we depend on digital

technologies to interpret seismic data, manage drilling rigs, production equipment and gathering systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems, networks, and those of its vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of its business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. We do not maintain specialized insurance for possible liability resulting from a cyberattack on our assets that may shut down all or part of 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, 2015, we had total indebtedness (net of associated accrued discount and premiums and unamortized debt issuance costs) of approximately \$946.3 million, including \$944.6 million attributable to our senior notes. We had borrowing base availability of \$521.4 million under our secured revolving credit facility after giving effect to an aggregate of \$178.6 million of letters of credit and no outstanding borrowings.

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 senior notes and our other indebtedness, which will reduce the funds available to us for operations and other purposes;
- our 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 \$700.0 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, 2015, we had no borrowings under our revolving credit facility. However, we intend to borrow 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, 2015, our borrowing base under our revolving credit facility was set at \$700.0 million and we had no 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, 2015, we had no variable interest rate borrowings outstanding; therefore, an increase in interest rates would not have impacted our interest expense. However, any increase in our interest rate at the time we do 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. As of December 31, 2015, we did not hedge our interest rate risk.

If we experience liquidity concerns, we could face a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit are, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit and increase our borrowing costs.

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, 2015, we had a net operating loss, or NOL, carry forward of approximately \$132.0 million for federal income tax purposes. Transfers of our stock 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 10, 2016, there were 108,324,750 shares of our common stock issued and outstanding, excluding 491,026 shares of unvested restricted stock awarded 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 3 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

Evaluation and Review of Reserves.

Reserve estimates at December 31, 2015 were prepared by NSAI with respect to our assets in the Utica Shale in Eastern Ohio (99% of our proved reserves at December 31, 2015) and our WCBB, Hackberry and Niobrara fields (1% of our proved reserves at December 31, 2015). Reserve estimates at December 31, 2014 and 2013 were prepared by Ryder Scott with respect to our assets in the Utica Shale in Eastern Ohio and by NSAI with respect to our WCBB, Hackberry and Niobrara fields. Our personnel prepared reserve estimates with respect to our overriding royalty and non-operated interests (less than 1% of our proved reserves) at December 31, 2015, 2014 and 2013.

NSAI is an independent petroleum engineering firm. A copy of the summary reserve reports is included as Exhibit 99.1 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.

In 2015, we made the decision to transfer the engineering of our Utica Shale reserves from Ryder Scott to NSAI. NSAI prepares the reserve estimates for several of the other operators located in close proximity to our Utica Shale acreage and brings specific expertise in the Utica Shale. In addition, NSAI has historically engineered our other operated fields and we believe we will benefit from synergies having the majority of our reserves engineered by one firm.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with 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 NSAI periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to 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 2015, 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, 2015, 2014 and 2013:

	Year Ended December 31,								
	2015			2014			2013		
	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	6,120	652,961	12,910	5,719	345,166	12,379	5,609	94,552	3,527
Proved undeveloped	338	907,184	4,826	3,778	373,840	13,889	2,737	51,894	2,148
Total (1)	<u>6,458</u>	<u>1,560,145</u>	<u>17,736</u>	<u>9,497</u>	<u>719,006</u>	<u>26,268</u>	<u>8,346</u>	<u>146,446</u>	<u>5,675</u>

	Year Ended December 31,		
	2015	2014	2013
Total net proved oil and natural gas reserves (MMcfe) (1)	<u>1,705,312</u>	<u>933,598</u>	<u>230,574</u>
PV-10 value (in millions) (2)	\$ 765.8	\$ 1,840.8	\$ 696.9
Standardized measure (in millions) (3)	\$ 764.3	\$ 1,427.2	\$ 578.5

- (1) Estimates of reserves as of year-end 2015, 2014 and 2013 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, 2015, 2014 and 2013, respectively, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2015, 2014 and 2013. 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, 2015, 2014 and 2013 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 \$50.28 per barrel and \$2.59 per MMBtu for 2015, \$94.99 per barrel and \$4.35 per MMBtu for 2014 and \$96.78 per barrel and \$3.67 per MMBtu for 2013, 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,		
	2015	2014	2013
		(In thousands)	
Standardized measure of discounted future net cash flows	\$764,331	\$1,427,167	\$578,466
Add: Present value of future income tax discounted at 10%	1,432	413,671	118,445
PV-10 value	<u>\$765,763</u>	<u>\$1,840,838</u>	<u>\$696,911</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.*”

As noted above, our December 31, 2015 proved reserves were calculated using prices based on the 12-month unweighted arithmetic average of the first-day-of-the month price for the period January through December 2015 of \$50.28 per barrel and \$2.59 per MMBtu. Holding production and development costs constant, if our 2015 reserves were calculated using the December 31, 2015 price of \$37.18 per barrel and \$2.28 per MMBtu, our discounted future net cash flows before income taxes would have been approximately \$453.0 million, or \$312.8 million less than our actual PV-10 value of \$765.8 million at December 31, 2015.

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, 2015, 2014 and 2013 and changes in proved reserves during the

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

Proved Undeveloped Reserves (PUDs)

As of December 31, 2015, our proved undeveloped reserves totaled 338 MBbls of oil, 907,184 MMcf of natural gas and 4,826 MBbls of NGLs, for a total of 938,168 MMcfe. Almost all of our PUDs at year-end 2015 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 2015, we made slight adjustments to our development plan with respect to our PUD locations booked in our reserve report for the year ended December 31, 2014 and scheduled to be drilled during 2015. Specifically, due to the continued significant decline in commodity prices during 2015, we did not drill six operated locations originally scheduled to be drilled in 2015, instead replacing these six locations with more economic non-PUD locations. In addition, one PUD location that was scheduled to be drilled by another operator in 2015 was not drilled and rescheduled to be drilled in 2016.

Changes in PUDs that occurred during 2015 were primarily due to:

- Additions of 625.9 Bcfe primarily attributable to 2015 extensions in our Utica field;
- Conversion of approximately 81.2 Bcfe attributable to 14 PUDs into proved developed reserves;
- Additions of 13.9 Bcfe attributable to four PUDs drilled during 2015 that were waiting on completion and pipeline connection and, as such, remain categorized as PUDs at December 31, 2015;
- Acquisition of approximately 271.8 Bcfe in our Paloma acquisition; and
- Downward revisions of 372.1 Bcfe due to the exclusion of PUD locations in our Southern Louisiana and Utica fields due to lower commodity prices and changes in the drilling timeline due to lower commodity prices.

We drilled approximately 18.6% of our December 31, 2014 PUD locations during the year ended December 31, 2015.

Costs incurred relating to the development of PUDs were approximately \$112.1 million in 2015. Estimated future development costs relating to the development of PUDs are projected to be approximately \$170.3 million in 2016, \$177.6 million in 2017, \$158.4 million in 2018, \$252.1 million in 2019 and \$78.8 million in 2020.

All PUD drilling locations included in our 2015 reserve report are scheduled to be drilled within five years of initial booking.

As of December 31, 2015, 5% of our total proved reserves were classified as proved developed non-producing.

As noted above, our December 31, 2015 proved reserves were calculated using prices based on the 12-month unweighted arithmetic average of the first-day-of-the month price for the period January through December 2015 of \$50.28 per barrel and \$2.59 per MMBtu. Holding production and development costs constant, if SEC pricing were \$40.00 per barrel and \$2.00 per MMBtu, this would have resulted in a loss of 921.2 Bcfe of our PUD volumes at December 31, 2015. Holding production and development costs constant, if SEC pricing were \$30.00 per barrel and \$1.75 per MMBtu, this would have resulted in a loss of 928.5 Bcfe of our PUD volumes at December 31, 2015.

Production, Prices and Production Costs

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

	<u>2015</u>	<u>2014</u>	<u>2013</u>
Production Volumes:			
Oil (MBbls)	2,899	2,684	2,317
Gas (MMcf)	156,151	59,318	8,891
Natural gas liquids (MGal)	185,792	86,092	13,416
Gas equivalents (MMcfe)	200,089	87,719	24,709
Average Prices:			
Oil (per Bbl)	\$ 48.91(1)	\$ 92.18(1)	\$ 96.74(1)
Gas (per Mcf)	\$ 3.25(1)	\$ 5.55(1)	\$ 2.36
Natural gas liquids (per Gal)	\$ 0.32(1)	\$ 1.09	\$ 1.27
Gas equivalents (per Mcfe)	\$ 3.54	\$ 7.65	\$ 10.61
Production Costs:			
Average production costs (per Mcfe)	\$ 0.35	\$ 0.59	\$ 1.08
Average production taxes and midstream costs (per Mcfe)	\$ 0.77	\$ 1.01	\$ 1.54
Total production and midstream costs and production taxes (per Mcfe)	<u>\$ 1.12</u>	<u>\$ 1.60</u>	<u>\$ 2.62</u>

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

	<u>Per barrel</u>
January - December 2015	\$ 62.36
January - December 2014	\$102.79
January - December 2013	\$100.90
	<u>Per MMBtu</u>
January - December 2015	\$ 3.94
January - December 2014	\$ 4.06
January - December 2013	\$ 4.00
	<u>Per gallon</u>
January - December 2015	\$ 0.48

Excluding the effect of fixed price swaps, the average price for 2015 would have been \$42.29 per barrel of oil, \$2.08 per Mcf of gas, \$0.31 per gallon of NGL and \$2.53 per Mcfe. The total volume hedged for 2015 represented approximately 46% of our total sales volumes for the year. 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 swap contracts, 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.

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, 2015:

	Year Ended December 31,		
	2015	2014	2013
Utica Shale			
Net Production			
Oil (MMbbls)	1,608	883	315
Gas (MMcf)	155,926	58,919	8,439
NGL (Mgal)	185,753	86,051	13,384
Total (MMcfe)	192,108	76,512	12,238
Average Sales Price:			
Oil (per Bbl)	\$ 42.41	\$ 78.63	\$ 83.67
Gas (per Mcf)	\$ 3.25	\$ 5.56	\$ 2.29
NGL (per Gal)	\$ 0.32	\$ 1.09	\$ 1.27
Average Production Cost (per Mcfe)	\$ 0.25	\$ 0.38	\$ 0.59

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, 2015.

Field	NRI/WI (1)	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)	39.11/48.15	82	36.96	224	110.53	3	2.66	—	—	36,549	32,110	203,931	201,469
West Cote Blanche Bay Field (5)	80.108/100	98	98	—	—	185	185	17	17	5,668	5,668	—	—
E. Hackberry Field (6)	79.91/100	21	21	—	—	124	124	—	—	2,910	2,910	1,206	1,206
W. Hackberry Field	80.00/100	5	5	—	—	8	8	—	—	1,192	1,192	—	—
Niobrara Formation (7)	38.94/46.77	4	2	—	—	2	1	—	—	2,740	1,370	7,415	3,624
Bakken Formation (8)	1.51/1.83	18	0.3	—	—	—	—	—	—	1,861	163	3,505	701
Overrides/Royalty Non-operated	Various	541	0.71	—	—	—	—	—	—	—	—	—	—
Total		769	163.97	224	110.53	322	320.66	17	17	50,920	43,413	216,057	207,000

(1) Net Revenue Interest (NRI)/Working Interest (WI).

(2) Includes two gross and net wells at WCBB that are producing intermittently.

(3) Developed acres are acres spaced or assigned to productive wells. Approximately 17% of our acreage is developed acreage and has been perpetuated by production.

(4) With respect to our total undeveloped Utica Shale acreage as of December 31, 2015, 24%, 9%, 18%, 1% and 12% is subject to expire in 2016, 2017, 2018, 2019 and 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 105 gross (12.03 net) gas wells and 36 gross (3.63 net) oil 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 36%, 7%, 8% and 39% of our total Niobrara undeveloped acreage are currently scheduled to expire in 2016, 2017, 2018 and 2019, 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.

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	72	72	161	161	150	150
Dry	—	—	—	—	—	—
Total	<u>72</u>	<u>72</u>	<u>161</u>	<u>161</u>	<u>150</u>	<u>150</u>
Development:						
Productive	49	38	119	100	80	63.8
Dry	—	—	7	6.8	2	2
Total	<u>49</u>	<u>38</u>	<u>126</u>	<u>106.8</u>	<u>82</u>	<u>65.8</u>
Exploratory:						
Productive	—	—	—	—	3	2.7
Dry	—	—	—	—	—	—
Total	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>3</u>	<u>2.7</u>

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
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	\$48.60	\$35.00
Second Quarter	52.28	39.29
Third Quarter	40.59	28.97
Fourth Quarter	36.12	20.21

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 09, 2016, there were 310 stockholders of record holding 108,322,250 shares of our outstanding common stock. There were approximately 32,247 beneficial owners of our common stock as of February 09, 2016.

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 restrict 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, 2015, December 31, 2014 and December 31, 2013 and the selected consolidated balance sheet data at December 31, 2015 and December 31, 2014 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, 2012 and December 31, 2011 and the selected consolidated balance sheet data at December 31, 2013, December 31, 2012 and December 31, 2011 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,				
	2015	2014	2013	2012	2011
	(In thousands, except share data)				
Selected Consolidated Statements of Operations					
Data:					
Revenues	\$ 709,475	\$ 671,266	\$ 262,753	\$248,926	\$229,254
Costs and expenses:					
Lease operating expenses	69,475	52,191	26,703	24,308	20,897
Production taxes	14,740	24,006	26,933	28,957	26,054
Midstream gathering and processing	138,590	64,467	11,030	443	279
Depreciation, depletion and amortization	337,694	265,431	118,880	90,749	62,320
Impairment of oil and gas properties	1,440,418	—	—	—	—
General and administrative	41,967	38,290	22,519	13,808	8,074
Accretion expense	820	761	717	698	666
(Gain) loss on sale of assets	—	(11)	508	(7,300)	—
	<u>2,043,704</u>	<u>445,135</u>	<u>207,290</u>	<u>151,663</u>	<u>118,290</u>
(Loss) Income from Operations	(1,334,229)	226,131	55,463	97,263	110,964
Other (Income) Expense:					
Interest expense	51,221	23,986	17,490	7,458	1,400
Interest income	(643)	(195)	(297)	(72)	(186)
Litigation settlement	—	25,500	—	—	—
Insurance proceeds	(10,015)	—	—	—	—
Gain on contribution of investments	—	(84,470)	—	—	—
Loss (income) from equity method investments	106,093	(139,434)	(213,058)	(8,322)	1,418
	<u>146,656</u>	<u>(174,613)</u>	<u>(195,865)</u>	<u>(936)</u>	<u>2,632</u>
(Loss) Income from Continuing Operations before					
Income Taxes	(1,480,885)	400,744	251,328	98,199	108,332
Income Tax (Benefit) Expense	(256,001)	153,341	98,136	26,363	(90)
(Loss) Income from Continuing Operations	<u>(1,224,884)</u>	<u>247,403</u>	<u>153,192</u>	<u>71,836</u>	<u>108,422</u>
Discontinued Operations:					
Loss on disposal of Belize properties, net of tax	—	—	—	3,465	—
Net (Loss) Income Available to Common Stockholders	<u>\$ (1,224,884)</u>	<u>\$ 247,403</u>	<u>\$ 153,192</u>	<u>\$ 68,371</u>	<u>\$108,422</u>
Net (Loss) Income Per Common Share - Basic:	<u>\$ (12.27)</u>	<u>\$ 2.90</u>	<u>\$ 1.98</u>	<u>\$ 1.22</u>	<u>\$ 2.22</u>
Net (Loss) Income Per Common Share - Diluted:	<u>\$ (12.27)</u>	<u>\$ 2.88</u>	<u>\$ 1.97</u>	<u>\$ 1.21</u>	<u>\$ 2.20</u>

	At December 31,				
	2015	2014	2013	2012	2011
	(In thousands)				
Selected Consolidated Balance Sheet Data:					
Total assets	\$3,334,734	\$3,619,473	\$2,685,039	\$1,569,431	\$691,158
Total debt, including current maturity	\$ 946,263	\$ 703,564	\$ 291,090	\$ 290,101	\$ 2,283
Total liabilities	\$1,295,897	\$1,323,177	\$ 634,801	\$ 443,023	\$ 58,808
Stockholders' equity	\$2,038,837	\$2,296,296	\$2,050,238	\$1,126,408	\$632,350

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. At December 31, 2015, 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 periods prior to the year ended December 31, 2014 which was expressed in barrels of oil equivalent. The current 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 our financial statements for periods prior to the year ended December 31, 2014 to conform to the current presentation.

Prices for oil and natural gas have historically been volatile and subject to significant fluctuation in response to changes in supply and demand, market uncertainty and a variety of other factors beyond our control. The decline in commodity prices that began in mid-2014 continued during 2015. In response to these declining commodity prices, during 2015 we reduced our capital expenditures by approximately 36% as compared to 2014 and continued to focus on operational efficiencies in an effort to reduce our overall well costs and deliver better results in a more economical manner. We currently estimate that our total capital expenditure budget for 2016 will be in the range of \$425.0 million to \$475.0 million, an approximate 36% to 43% decrease from our total capital expenditures in 2015.

With commodity prices declining further in early 2016 to reach multi-year lows, we remain focused on capital discipline, conservative leverage and creating long-term value for our stockholders. We will continue to monitor the commodity price environment and expect to maintain financial flexibility to adjust our drilling and completion plans to appropriately respond to market conditions. To maintain financial flexibility, we chose to complete our spring borrowing base redetermination under our revolving credit facility earlier in 2016, which resulted in the bank syndicate affirming and maintaining the existing \$700.0 million borrowing base under this

facility. We believe that the quality of our asset base, our robust reserve growth during 2015 and our strong hedge position contributed to this determination, despite the current commodity price environment. As of December 31, 2015, our revolving credit facility was undrawn with outstanding letters of credit totaling \$178.6 million, and we had cash on hand of approximately \$113.0 million. See “- *Liquidity and Capital Resources*” below.

2015 and 2016 Year to Date Highlights

- Production increased 128% to approximately 200,089 MMcfe for the year ended December 31, 2015 from approximately 87,719 MMcfe for the year ended December 31, 2014.
- Oil and natural gas revenues increased 6% to \$709.0 million for the year ended December 31, 2015 from \$670.8 million for the year ended December 31, 2014.
- During 2015, we spud 49 gross (38.4 net) wells, participated in an additional 25 gross (7.3 net) wells that were drilled by other operators on our Utica Shale acreage and recompleted 72 gross and net wells. Of our 49 new wells spud during 2015, ten were completed as producing wells and, at year end, 36 were in various stages of completion and three were drilling.
- In August 2015, we acquired Paloma for a total purchase price of approximately \$301.9 million. Paloma holds approximately 24,000 net nonproducing acres in the Utica Shale of Ohio.
- On April 21, 2015, we issued 10,925,000 shares of our common stock in an underwritten public offering. The net proceeds from this equity offering were approximately \$501.8 million. We used a portion of these net proceeds, together with a portion of the net proceeds from our concurrent senior notes offering described below, to repay all borrowings outstanding at that time under our senior secured revolving credit facility and to fund the acquisition of Paloma and used the remaining funds from these offerings for general corporate purposes, including the funding of a portion of our 2015 capital development plans.
- On April 21 2015, we issued \$350.0 million in aggregate principal amount of our 6.625% senior unsecured notes due 2023, resulting in net proceeds to us of \$343.6 million.
- On June 12, 2015, we issued 11,500,000 shares of our common stock in an underwritten public offering. The net proceeds from this equity offering were approximately \$479.7 million. We used a portion of these net proceeds to fund the acquisition of certain acreage and other assets in the Utica Shale in Ohio from AEU, described below, and used the remaining funds for general corporate purposes, including the funding of a portion of our 2015 capital development plans.
- On June 9, 2015, we completed the acquisition of 6,198 gross and net acres located in Belmont and Jefferson Counties, Ohio from AEU for a purchase price of approximately \$68.2 million in a transaction we refer to as the Belmont/Jefferson acquisition. This acreage is located near or adjacent to the acreage included in our acquisition of Paloma. This newly acquired Belmont and Jefferson County acreage is undeveloped.
- On June 12, 2015, we completed the acquisition of 38,965 gross (27,228 net) acres located in Monroe County, Ohio, which we refer to as the Monroe County Acreage, 14.6 MMcf per day of average net production (estimated for April 2015), 18 gross (11.3 net) drilled but uncompleted wells, an 11 mile gas gathering system and a four well pad location from AEU for a total purchase price of approximately \$319.0 million, which we refer to as the Monroe Acquisition. We used a portion of the net proceeds from our June 2015 equity offering described above to fund the Monroe Acquisition. The Monroe County Acreage has a net revenue interest of approximately 84% and is approximately 85% held by production by a ten well per year drilling commitment. On June 29, 2015, we acquired an additional 4,950 gross (1,900 net) acres in Monroe County for an additional approximately \$18.2 million from AEU.

- As of February 10, 2016, we held leasehold interests in approximately 244,000 gross (237,000 net) acres in the Utica Shale. During 2015, we spud 49 gross (38.4 net) wells on our Utica Shale acreage and, during 2016 (through February 10, 2016), we had spud four gross (2.2 net) wells. As of February 10, 2016, one well was waiting on completion and three were still being drilled.

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 \$1.8 billion at December 31, 2015 and \$1.5 billion at December 31, 2014. 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 (as defined in the preceding paragraph). 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. As a result of the decline in commodity prices, we recognized a ceiling test impairment of \$1.4 billion for the year ended December 31, 2015. If prices of oil,

natural gas and natural gas liquids continue to decline, we may be required to further write down the value of our oil and natural gas properties, which could negatively affect our results of operations.

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. Netherland, Sewell & Associates, Inc. and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2015 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 basis 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, 2015, a valuation allowance of \$281.8 million had been established for the net deferred tax asset, with the exception of certain NOL's and alternative minimum tax, or AMT, credits that we expect to utilize 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 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 was multiplied by the total shares owned by us and the resulting gain or loss was 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. For the year ended December 31, 2015, we recognized an impairment loss related to our investment in Grizzly of approximately \$101.6 million. At December 31, 2014, we fully impaired our investment in Tatex III.

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. We seek to reduce our exposure to unfavorable changes in oil, natural gas and natural gas liquids prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps and various types of option 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 industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. While we have historically designated derivative instruments as accounting hedges, effective January 1, 2015, we discontinued hedge accounting prospectively. Our current commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

See Item 7. “Commodity Price Risk” for a summary of our derivative instruments in place as of December 31, 2015.

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:

	<u>2015</u>	<u>2014</u>	<u>2013</u>
Production Volumes:			
Oil (MBbls)	2,899	2,684	2,317
Gas (MMcf)	156,151	59,318	8,891
Natural gas liquids (MGal)	185,792	86,092	13,416
Gas equivalents (MMcfe)	200,089	87,719	24,709
Average Prices:			
Oil (per Bbl)	\$ 48.91(1)	\$ 92.18(1)	\$ 96.74(1)
Gas (per Mcf)	\$ 3.25(1)	\$ 5.55(1)	\$ 2.36(1)
Natural gas liquids (per Gal)	\$ 0.32(1)	\$ 1.09	\$ 1.27
Gas equivalents (per Mcfe)	\$ 3.54	\$ 7.65	\$ 10.61
Production Costs:			
Average production costs (per Mcfe)	\$ 0.35	\$ 0.59	\$ 1.08
Average production taxes and midstream costs (per Mcfe)	\$ 0.77	\$ 1.01	\$ 1.54
Total production and midstream costs and production taxes (per Mcfe)	<u>\$ 1.12</u>	<u>\$ 1.60</u>	<u>\$ 2.62</u>

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

	<u>Per barrel</u>
January – December 2015	\$ 62.36
January – December 2014	\$102.79
January – December 2013	\$100.90
	<u>Per MMBtu</u>
January – December 2015	\$ 3.94
January – December 2014	\$ 4.06
January – December 2013	\$ 4.00
	<u>Per gallon</u>
January – December 2015	\$ 0.48

Excluding the net effect of fixed price swaps, the average prices for 2015 would have been \$42.29 per barrel of oil, \$2.08 per Mcf of gas, \$0.31 per gallon of NGL and \$2.53 per Mcfe. The total volume hedged for 2015 represented approximately 46% of our total sales volumes for the year. Excluding the effect of fixed price swaps, the average prices 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 net effect of fixed price swaps, the average prices 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.

From 2014 to 2015, our net equivalent gas production increased 128% from 87,719 MMcfe to 200,089 MMcfe primarily as a result of the development of our Utica Shale acreage. From 2013 to 2014, our net equivalent gas production also increased 255% from 24,709 MMcfe to 87,719 MMcfe primarily as a result of the development of our Utica Shale acreage. We currently estimate that our 2016 production will be between 254,370 and 267,180 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, 2015 and December 31, 2014

We reported a net loss of \$1.2 billion for the year ended December 31, 2015 as compared to net income of \$247.4 million for the year ended December 31, 2014. This decrease in period-to-period net income was due primarily to an impairment charge of \$1.4 billion, a 54% decrease in realized Mcfe prices to \$3.54 from \$7.65, a \$17.3 million increase in lease operating expenses, a \$74.1 million increase in midstream gathering and processing expenses, a \$3.7 million increase in general and administrative expenses, a \$245.5 million decrease in income from equity method investments and a \$27.2 million increase in interest expense, partially offset by a 128% increase in net production to 200,089 MMcfe from 87,719 MMcfe, \$10.0 million of insurance proceeds and a \$409.3 million decrease in income tax expense for the year ended December 31, 2015, as compared to the year ended December 31, 2014. In addition, our 2014 net income included \$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 and \$84.5 million of income recognized from our contribution of investments to Mammoth.

Oil and Gas Revenues. For the year ended December 31, 2015, we reported oil and natural gas revenues of \$709.0 million as compared to oil and natural gas revenues of \$670.8 million during 2014. This \$38.2 million, or 6%, increase in revenues was primarily attributable to a 128% increase in net production to 200,089 MMcfe from 87,719 MMcfe, partially offset by a 54% decrease in realized Mcfe prices to \$3.54 from \$7.65 due the decline in commodity prices and a shift in our production mix toward natural gas and NGLs for the year ended December 31, 2015 as compared to the year ended December 31, 2014.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2015 and December 31, 2014:

	Year Ended December 31,	
	2015	2014
Oil production volumes (MBbls)	2,899	2,684
Gas production volumes (MMcf)	156,151	59,318
Natural gas liquids production volumes (MGal)	185,792	86,092
Gas equivalents (MMcfe)	200,089	87,719
Average oil price (per Bbl)	\$ 48.91	\$ 92.18
Average gas price (per Mcf)	\$ 3.25	\$ 5.55
Average natural gas liquids (per Gal)	\$ 0.32	\$ 1.09
Gas equivalents (per Mcfe)	\$ 3.54	\$ 7.65

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to \$69.5 million for the year ended December 31, 2015 from \$52.2 million for the year ended December 31, 2014. This increase was mainly the result of an increase in expenses related to property taxes, contract labor and field supervision, field telemetry, location repair, rentals, facility repairs and maintenance and water hauling and disposal due to our increased production in the Utica Shale.

Production Taxes. Production taxes decreased to \$14.7 million for the year ended December 31, 2015 from \$24.0 million for 2014. This decrease was primarily related to changes in our product mix and production location, as well as the decline in commodity prices.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased by \$74.1 million to \$138.6 million for the year ended December 31, 2015 from \$64.5 million for 2014. This increase was primarily the result of midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2015 and 2014 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to \$337.7 million for the year ended December 31, 2015, and consisted of \$335.3 million in depletion of oil and natural gas properties and \$2.4 million in depreciation of other property and equipment, as compared to total DD&A expense of \$265.4 million for 2014. 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 \$42.0 million for the year ended December 31, 2015 from \$38.3 million for the year ended December 31, 2014. This \$3.7 million increase was due to an increase in salaries and benefits resulting from an increased number of employees, increases in fees for audit services, bank service charges, computer support and travel expense, partially offset by decreases in stock compensation expense, consulting expense, legal expense and franchise taxes and 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, 2015 and 2014.

Interest Expense. Interest expense increased to \$51.2 million for the year ended December 31, 2015 from \$24.0 million for the year ended December 31, 2014 due primarily to the issuance of \$300.0 million of additional 7.75% Senior Notes due 2020 on August 18, 2014, the issuance of \$350.0 million of 6.625% Senior Notes due 2023 on April 21, 2015 and increased borrowings under our revolving credit facility during 2015. Total weighted debt outstanding under our revolving credit facility was \$46.6 million for the year ended December 31, 2015 as compared to \$22.8 million outstanding under such facility for 2014. Additionally, we capitalized approximately \$13.3 million and \$9.7 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2015 and December 31, 2014, respectively. This increase in capitalized interest in the 2015 period was the result of an increase in our undeveloped oil and natural gas properties.

Income Taxes. As of December 31, 2015, we had a net operating loss carry forward of approximately \$132.0 million, in addition to numerous temporary differences, which gave rise to a net deferred tax asset as a result of recording a full cost ceiling impairment of \$1.4 billion. 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, 2015, a valuation allowance of \$281.8 million was established against the net deferred tax asset, with the exception of certain state NOL's and AMT credits that we expect to be able to utilize with net operating loss carrybacks and tax planning in the amount of \$24.2 million. We recognized an income tax benefit from continuing operations of \$256.0 million for the year ended December 31, 2015.

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.

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 2015, we received net proceeds of approximately \$343.6 million from the sale of our 6.625% Senior Notes due 2023 issued in April 2015. In addition, we received an aggregate of \$981.5 million in net proceeds from the sale of our shares of common stock in underwritten public offerings completed in April and June 2015. We also received approximately \$10.0 million of net insurance proceeds in October 2015 related to a 2014 litigation settlement. 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 \$322.2 million for the year ended December 31, 2015 as compared to net cash flow provided by operating activities of \$409.9 million for 2014. This decrease was primarily the result of a 54% decrease in net realized Mcfe prices and increases in our operating expenses due to

our increased activity in the Utica Shale, partially offset by an increase in cash receipts from our oil and natural gas purchasers due to a 128% increase in our net Mcfe production.

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 Mcfe prices.

Net cash used in investing activities for the year ended December 31, 2015 was \$1.6 billion as compared to \$1.1 billion for 2014. During the year ended December 31, 2015, we spent \$1.6 billion in additions to oil and natural gas properties, of which \$217.6 million was spent on our 2015 drilling and recompletion programs, \$512.0 million was spent on expenses attributable to the wells drilled and recompleted during 2014, \$705.1 million was spent on the AEU and Paloma acquisitions, \$9.9 million was spent on facility enhancements, \$3.1 million was spent on plugging costs and \$96.2 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, \$14.5 million was invested in Grizzly. We did not make any material investments in our other equity investments during the year ended December 31, 2015. During the year ended December 31, 2015, we used cash from operations and proceeds from our 2014 and 2015 equity and debt offerings for our investing activities.

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 \$1.3 billion 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 provided by financing activities for the year ended December 31, 2015 was \$1.2 billion as compared to net cash provided by financing activities of \$410.2 million for 2014. The 2015 amount provided by financing activities is primarily attributable to the gross proceeds of \$350.0 million from our 2015 debt offering and net proceeds of \$981.5 million from our 2015 equity offerings.

Net cash provided by financing activities for the year ended December 31, 2014 was \$410.2 million as compared to \$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.

Credit Facility. We have entered into a senior secured revolving credit facility, as amended, with The Bank of Nova Scotia, as the lead arranger and administrative agent and certain lenders from time to time party thereto. The credit agreement provides for a maximum facility amount of \$1.5 billion and matures on June 6, 2018. As of December 31, 2015, we had no balance outstanding under our revolving credit facility and total funds available for borrowing, after giving effect to an aggregate of \$178.6 million of letters of credit, were \$521.4 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 facility 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.

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 4.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with these financial covenants at December 31, 2015.

We chose to complete our spring borrowing base redetermination under the Company’s revolving credit facility ahead of schedule and the bank syndicate affirmed and maintained the existing \$700.0 million borrowing base.

Senior Notes. In October 2012, December 2012 and August 2014, we issued an aggregate of \$600.0 million in principal amount of our 7.75% senior notes due 2020 which were subsequently exchanged for substantially identical senior notes registered under the Securities Act. These senior notes, which were issued under an indenture among us, our subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee, are treated as a single class of debt securities under the senior note indenture and are referred to collectively as the 2020 Notes. Interest on the 2020 Notes accrues at a rate of 7.75% per annum on the outstanding principal amount payable semi-annually on May 1 and November 1 of each year. The 2020 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. We may redeem some or all of the 2020 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 2020 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 2020 Notes initially issued remains outstanding immediately after such redemption.

In April 2015, we issued an aggregate of \$350.0 million in principal amount of our 6.625% senior notes due 2023 under a new indenture, dated as of April 21, 2015, among us, our subsidiary guarantors and Wells Fargo Bank, N.A., as trustee. Interest on these senior notes, which we refer to as the 2023 Notes, accrues at a rate of 6.625% per annum on the outstanding principal amount thereof from April 21, 2015, payable semi-annually on May 1 and November 1 of each year, commencing on November 1, 2015. The 2023 Notes will mature on May 1, 2023 and are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness, including the 2020 Notes, and senior in right of payment to any of our future subordinated indebtedness. We may redeem some or all of the 2023 Notes at any time on or after May 1, 2018, at the redemption prices listed in the indenture relating to the 2023 Notes. Prior to May 1, 2018, we may redeem all or a portion of the 2023 Notes at a price equal to 100% of the principal amount of the 2023 Notes plus a “make-whole” premium and accrued and unpaid interest to the redemption date. In addition, any time prior to May 1, 2018, we may redeem the 2023 Notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2023 Notes issued prior to such date at a redemption price of 106.625%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

All of our existing and future restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt guarantee the 2020 Notes and the 2023 Notes, provided, however, that the 2020 Notes and the 2023 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 2020 Notes and the 2023 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 amended and restated credit agreement) 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 2020 Notes and the 2023 Notes.

If we experience a change of control (as defined in the senior note indentures relating to the 2020 Notes and the 2023 Notes), we will be required to make an offer to repurchase the 2020 Notes and the 2023 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 our senior note indentures, we will be required to use the remaining proceeds to make an offer to repurchase the 2020 Notes and the 2023 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 indentures relating to the 2020 Notes and the 2023 Notes contain 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. Under the indenture relating to the 2023 Notes, certain of these covenants are subject to termination upon the occurrence of certain events, including in the event the 2023 Notes are ranked as “investment grade.”

In connection with the 2023 Notes Offering, we and our subsidiary guarantors entered into a registration rights agreement with the representatives of the initial purchasers, dated as of April 21, 2015, pursuant to which we agreed to file a registration statement with respect to an offer to exchange the 2023 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 2023 Notes was filed on August 24, 2015 and declared effective by the SEC on September 4, 2015. The exchange offer for the 2023 Notes was completed on October 13, 2015.

Construction Loan. On June 4, 2015, we entered into a construction loan agreement, or the construction loan, with InterBank for the construction of our new corporate headquarters in Oklahoma City. The construction

loan allows for maximum principal borrowings of \$24.5 million and requires us to fund 30% of the cost of the construction before any funds can be drawn, which occurred in January 2016. Interest accrues daily on the outstanding principal balance at a fixed rate of 4.50% per annum and is payable on the last day of the month through May 31, 2017. Monthly interest and principal payments are due beginning June 30, 2017, with the final payment due June 4, 2025. As of December 31, 2015, we had no borrowings under the construction loan.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions primarily in the Utica Shale, 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, 2015, 55.0% 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 2015, we spud 49 gross (38.4 net) wells in the Utica Shale for a total cost of approximately \$253.5 million. In addition, 25 gross (7.3 net) wells were drilled by other operators on our Utica Shale acreage during 2015 for a total cost to us of approximately \$38.8 million. We currently expect our 2016 capital expenditures to be \$219.0 million to \$247.0 million to drill 29 to 32 gross (19 to 21 net) horizontal wells and commence sales from 44 to 48 gross (28 to 30 net) wells on our Utica Shale acreage. As of February 10, 2016, we had three operated horizontal rigs drilling in the play. We also anticipate an additional 17 to 19 gross (two to three net) horizontal wells will be drilled, and sales commenced from 30 to 34 gross (eight to nine net) horizontal wells, on our Utica Shale acreage by other operators for estimated 2016 expenditures to us of \$90.0 million to \$100.0 million. In addition, we currently expect to spend \$60.0 million to \$65.0 million in 2016 for acreage expenses, primarily lease extensions, in the Utica Shale.

During 2015, we recompleted 35 existing wells and spud no new wells for a total cost of approximately \$8.1 million at our WCBB field. In our Hackberry fields, in 2015, we recompleted 37 existing wells and spud no new wells for a total cost of approximately \$4.9 million. We currently expect to spend \$26.0 million to \$28.0 million in 2016 for maintenance capital expenditures and recompletions in Southern Louisiana.

During 2015, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2016.

During the third quarter of 2006, we purchased a 24.9% interest in Grizzly. As of December 31, 2015, our net investment in Grizzly was approximately \$50.6 million. Our capital requirements in 2015 for Grizzly were approximately \$14.5 million. Effective October 5, 2012, Grizzly entered into a \$125.0 million revolving credit facility, of which \$57.4 million was outstanding at December 31, 2015. Grizzly has agreed to pay the outstanding balance by the maturity date of June 2016, of which our proportionate share is approximately \$14.4 million. We do not currently anticipate any additional material capital expenditures in 2016 related to Grizzly's activities.

We had no material capital expenditures during the year ended December 31, 2015 related to our interests in Thailand. We do not currently anticipate any capital expenditures in Thailand in 2016.

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. See Item 1. "Business - Our Equity Investments" and Note 4 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. During the year ended December 31, 2015, we did not make any additional investments in these entities, and we do not currently anticipate any capital expenditures related to these entities in 2016. We are currently evaluating strategic alternatives with respect to some of 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 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 its proposed initial public offering. Mammoth originally intended to pursue the offering in 2015; however, Mammoth continues to evaluate market conditions and the commodity price environment which will impact the timing of the proposed offering. 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. During the year ended December 31, 2015, we received net proceeds of \$7.2 million from the release of escrow from the Blackhawk sale.

In February 2016, we entered into a joint venture with Rice to develop natural gas gathering assets in eastern Belmont County and Monroe County, Ohio, which we refer to as the dedicated areas. We own a 25% interest in the joint venture and Rice acts as operator and owns the remaining 75% interest in the joint venture. Construction of the gathering assets, which is underway, is expected to provide connectivity of our dry gas gathering systems and interchangeability of natural gas across our firm portfolio.

The joint venture has completed the first phase of the projects: a lateral that connects two existing dry gas gathering systems on which we currently flow the majority of our dry gas volumes. The lateral has been commissioned and first flow commenced on February 1, 2016. In addition, we and Rice have agreed to negotiate in good faith to expand the joint venture to provide water services to us within the dedicated areas. In connection with the formation of the joint venture, we contributed certain assets, including an approximately 11 mile-long, 12-inch diameter gathering line. We currently anticipate that we will also make \$30.0 million to \$35.0 million in cash contributions to the joint venture in 2016.

During 2015, we continued to focus on operational efficiencies in an effort to reduce our overall well costs and deliver better results in a more economical manner, particularly in light of the continued downturn in commodity prices. To do so, we have leveraged the lower commodity price environment to gain access to higher-quality equipment and superior services for reduced costs, which has contributed to increased productivity. To further benefit from these efficiencies and cost savings, we elected to accelerate our completion activities in late 2015 in advance of the winter months when operations are less efficient and more costly due to the cold weather. Our total capital expenditures for 2016 are currently estimated to be in the range of \$335.0 million to \$375.0 million for drilling and completion expenditures. In addition, we currently expect to spend \$60.0 million to \$65.0 million in 2016 for acreage expenses, primarily lease extensions, in the Utica Shale and \$30.0 million to \$35.0 million to fund our recent joint venture with Rice. Approximately 94% of our 2016 estimated capital expenditures are currently expected to be spent in the Utica Shale. The 2016 range is down from the \$851.8 million spent in 2015, which excludes Utica leasehold acquisitions (including the AEU and Paloma acquisitions), primarily due to current commodity prices and a desire to maintain a favorable liquidity position. As a result of the decline in commodity prices, our 2016 development plan contemplates running an average of 2.5 rigs on our operated Utica Shale acreage, as compared to an average of 3.7 rigs in 2015. Strong results from our existing production base and efficiencies realized in our completion activities resulted in our 2015 production trending ahead of expectations. Taking into consideration our strong production results, realized efficiencies and the weakness in natural gas commodity pricing, we made the decision to idle completion crews and suspend our hydraulic fracturing activities during the first quarter of 2016 and have entered into an agreement with one of our service providers that adjusts the amount of service fees that would otherwise be payable during this period. We anticipate resuming these activities in April 2016.

We continually monitor market conditions and are prepared to adjust our drilling program if commodity prices dictate. Currently, we believe that our cash flow from operations, cash on hand and borrowings under our loan agreements will be sufficient to meet our normal recurring operating needs and capital requirements for the

next twelve months. In the event commodity prices decline further, our capital or other costs increase, our equity investments require additional contributions and/or we pursue additional equity method investments or acquisitions, 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. Further, 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. If the decline in commodity prices continues or worsens, our revenues, cash flows, results of operations, liquidity and reserves may be materially and adversely affected.

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 \$27.56 per barrel, or Bbl, in January 2016 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 \$1.80 per MMBtu in December 2015 to a high of \$7.51 per MMBtu in January 2010. During 2015, WTI prices ranged from \$36.48 to \$65.69 per Bbl and the Henry Hub spot market price of natural gas ranged from \$1.80 to \$3.65 per MMBtu. On January 20, 2016, the WTI posted price for crude oil was \$28.35 per Bbl and the Henry Hub spot market price of natural gas was \$2.12 per MMBtu, representing decreases of 57% and 42%, respectively, from the high of \$65.69 per Bbl of oil and \$3.65 per MMBtu for natural gas during 2015. 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, 2015.

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, 2015, the plugging and abandonment trust totaled approximately \$3.1 million. At December 31, 2015, we have plugged 463 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, 2015:

Contractual Obligations	Payment due by period				
	Total	Less than 1 year	1-3 years (In thousands)	3-5 years	More than 5 years
7.75% senior unsecured notes due 2020 (1)	\$ 830,627	\$ 46,500	\$ 93,000	\$ 691,127	\$ —
6.625% senior unsecured notes due 2023 (2)	523,906	23,188	46,375	46,375	407,968
Asset retirement obligations	26,437	75	684	703	24,975
Employment agreements	1,216	882	334	—	—
Building loan (3)	1,653	179	1,474	—	—
Firm transportation contracts	3,843,274	145,282	410,307	459,899	2,827,786
Purchase obligations (4)	144,210	52,440	91,770	—	—
Operating leases	1,437	800	637	—	—
Total	<u>\$5,372,760</u>	<u>\$ 269,346</u>	<u>\$ 644,581</u>	<u>\$1,198,104</u>	<u>\$3,260,729</u>

- (1) Includes estimated interest of \$46.5 million due in less than one year; \$93.0 million due in 1-3 years and \$91.1 million due in 3-5 years.
- (2) Includes estimated interest of \$23.2 million due in less than one year; \$46.4 million due in 1-3 years; \$46.4 million due in 3-5 years and \$58.0 million due thereafter.
- (3) Does not include estimated interest of \$63,000 due in less than one year and \$104,000 due in 1-3 years.
- (4) 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, 2015.

New Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. This ASU provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporation and securitization structure, should be consolidated. The ASU is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. The ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. We are in the process of evaluating the impact on our consolidated financial statements. This evaluation could result in certain of our equity investments being accounted for as variable interest entities.

In April 2015, the FASB issued ASU No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. To simplify presentation of debt issuance costs, ASU 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. ASU 2015-03 is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. We have reclassified \$17.9 million and \$12.9 million of debt issuance costs to offset long-term debt at December 31, 2015 and 2014, respectively, as shown in Note 6 to our consolidated financial statements included elsewhere in this Annual Report.

In September 2015, the FASB issued ASU No. 2015-16, *Simplifying the Accounting for Measurement-Period Adjustments*. The guidance eliminates the requirement to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated.

Measurement period adjustments are calculated as if they were known at the acquisition date, but are recognized in the reporting period in which they are determined. Additional disclosures are required about the impact on current-period income statement line items of adjustments that would have been recognized in prior periods if prior-period information had been revised. The guidance is effective for annual periods beginning after December 15, 2015 and is to be applied prospectively to adjustments of provisional amounts that occur after the effective date. Early adoption is permitted. We are in the process of evaluating this new guidance and do not expect it to have a material impact on our consolidated financial statements.

In November 2015, the FASB issued ASU No. 2015-17, *Balance Sheet Classification of Deferred Taxes (Topic 705)*. Current guidance requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. Deferred tax liabilities and assets are classified as current or noncurrent based on the classification of the related asset or liability for financial reporting. Deferred tax liabilities and assets that are not related to an asset or liability for financial reporting are classified according to the expected reversal date of the temporary difference. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred income tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This update is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. Earlier application is permitted for all entities as of the beginning of an interim or annual reporting period. We are in the process of evaluating the impact on our consolidated financial statements.

In April 2014, the FASB issued 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 was 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; however, in July 2015 the FASB decided to defer the effective date by one year (until 2018) by issuing ASU No. 2015-14, *Revenue from Contracts with Customers; Deferral of the Effective Date*. 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 \$27.56 per barrel, or Bbl, in January 2016 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 \$1.80 per MMBtu in December 2015 to a high of \$7.51 per MMBtu in January 2010. During 2015, WTI prices ranged from \$36.48 to \$65.69 per Bbl and the Henry Hub spot market price of natural gas ranged from \$1.80 to \$3.65 per MMBtu. On January 20, 2016, the WTI posted price for crude oil was \$28.35 per Bbl and the Henry Hub spot market price of natural gas was \$2.12 per MMBtu, representing decreases of 57% and 42%, respectively, from the high of \$65.69 per Bbl of oil and \$3.65 per MMBtu for natural gas during 2015. 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 swap positions as of December 31, 2015.

	<u>Location</u>	<u>Daily Volume (Bbls/day)</u>	<u>Weighted Average Price</u>
January 2016 – June 2016	ARGUS LLS	1,500	\$63.03
January 2016 – June 2016	NYMEX WTI	1,000	\$61.40
January 2016 – March 2016	NYMEX Henry Hub	415,000	\$ 3.56
April 2016	NYMEX Henry Hub	425,000	\$ 3.52
May 2016 – June 2016	NYMEX Henry Hub	355,000	\$ 3.42
July 2016 – September 2016	NYMEX Henry Hub	375,000	\$ 3.38
October 2016	NYMEX Henry Hub	405,000	\$ 3.33
November 2016 – December 2016	NYMEX Henry Hub	430,000	\$ 3.30
January 2017 – March 2017	NYMEX Henry Hub	317,500	\$ 3.25
April 2017 – June 2017	NYMEX Henry Hub	272,500	\$ 3.31
July 2017 – December 2017	NYMEX Henry Hub	210,000	\$ 3.12
January 2018 – December 2018	NYMEX Henry Hub	160,000	\$ 3.01
January 2019 – March 2019	NYMEX Henry Hub	20,000	\$ 3.37

	<u>Location</u>	<u>Daily Volume (Bbls/day)</u>	<u>Weighted Average Price</u>
January 2016 – December 2016	Mont Belvieu	1,000	\$20.16

We sold call options and used the associated premiums to enhance the fixed price for a portion of the fixed price natural gas swaps listed above. Each short call option has an established ceiling price. When the referenced settlement price is above the price ceiling established by these short call options, we pay our counterparty an amount equal to the difference between the referenced settlement price and the price ceiling multiplied by the hedged contract volumes.

	<u>Location</u>	<u>Daily Volume (MMBtu/day)</u>	<u>Weighted Average Price</u>
January 2016 – March 2016	NYMEX Henry Hub	75,000	\$3.25
April 2016 – December 2016	NYMEX Henry Hub	95,000	\$3.18
January 2017 – March 2017	NYMEX Henry Hub	20,000	\$2.91

For a portion of the combined natural gas derivative instruments containing fixed price swaps and sold call options, the counterparty has an option to extend the terms an additional twelve months for the period January 2017 through December 2017. These options expire in December 2016. If executed, we would have additional fixed price swaps for 30,000 MMBtu per day at a weighted average price of \$3.33 and additional short call options for 30,000 MMBtu per day at a weighted average ceiling price of \$3.33.

In addition, we have entered into natural gas basis swap positions, which settle on the pricing index to basis differential of MichCon or Tetco M2 to the NYMEX Henry Hub natural gas price. As of December 31, 2015, we had the following natural gas basis swap positions for MichCon and Tetco M2, respectively.

	<u>Location</u>	<u>Daily Volume (MMBtu/day)</u>	<u>Weighted Average Price</u>
January 2016 – March 2016	MichCon	70,000	\$ 0.11
April 2016 – December 2016	MichCon	40,000	\$ 0.02
November 2016 – March 2017	Tetco M2	50,000	\$(0.59)

In January of 2016, we entered into fixed price swaps for the period of February 2016 through March 2016, for 75,000 MMBtu of natural gas per day at a weighted average price of \$2.58 per MMBtu. For the period from April 2016 through December 2016, we entered into fixed price swaps for 95,000 MMBtu of natural gas per day at a weighted average price of \$2.59 per MMBtu. For the period from January 2017 through December 2017, we entered into fixed price swaps for 95,000 MMBtu of natural gas per day at a weighted average price of \$2.70 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 its counterparty the current market price as listed on NYMEX for natural gas.

Under our 2016 contracts, we have hedged approximately 69% to 72% of our expected 2016 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. At December 31, 2015, we had a net asset derivative position of \$186.5 million as compared to a net asset derivative position of \$102.8 million as of December 31, 2014, 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 \$80.6 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately \$80.6 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, 2015, we had no variable interest rate borrowings outstanding; therefore, an increase in interest rates would not have impacted our interest expense. As of December 31, 2015, 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 Accounting 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 Accounting Officer, as appropriate to allow timely decisions regarding required disclosures.

As of December 31, 2015, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and President and our Chief Accounting 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 Accounting Officer have concluded that, as of December 31, 2015, 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, 2015.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2015 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2015, as stated in their accompanying report.

/s/ Michael G. Moore

Name: Michael G. Moore

Title: Chief Executive Officer and President

/s/ Keri Crowell

Name: Keri Crowell

Title: Chief Accounting 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, 2015, 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, 2015, 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, 2015 and our report dated February 19, 2016 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 19, 2016

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*

<u>Exhibit Number</u>	<u>Description</u>
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).

Exhibit Number	Description
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	Indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of the Company's 6.625% Senior Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 21, 2015).
4.6	Voting Rights Waiver Agreement, dated June 10, 2015, by and among Gulfport Energy Corporation, Putnam Investment Management, LLC, The Putnam Advisory Company, LLC and Putnam Fiduciary Trust Company (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on June 12, 2015)
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+	Amended and Restated Employment Agreement, dated as of April 29, 2015, by and between the Company and Michael G. Moore (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 7, 2015).
10.8+	Employment Agreement, effective as of August 11, 2014, by and between the Company and Aaron Gaydosik (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on March 19, 2015).
10.9+	Employment Agreement, effective as of April 22, 2014, by and between the Company and Ross Kirtley (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on March 19, 2015).
10.10	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).

Exhibit Number	Description
10.11	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).
10.12	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).
10.13	Third Amendment to Amended and Restated Credit Agreement, dated as of April 10, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 15, 2015).
10.14	Fourth Amendment to Amended and Restated Credit Agreement, dated as of May 29, 2015, among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on August 7, 2015).
10.15	Fifth Amendment to Amended and Restated Credit Agreement, dated as of September 18, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on September 24, 2015).
10.16#	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).
10.17#	Amendment to Sand Supply Agreement, dated as of November 3, 2015, by and between Muskie Proppant LLC and Gulfport Energy Corporation (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 5, 2015).
10.18#	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).
10.19*##	Amendment to Amended and Restated Master Services Agreement, dated as of February 18, 2016 to be effective as of January 1, 2016, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC.
10.20+	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).
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.

Exhibit Number	Description
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 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 which portions have been omitted and filed separately with the SEC.

Confidential treatment requested as to certain portions, 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, 2015 and 2014, and the related consolidated statements of operations, comprehensive (loss) income, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2015. 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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Company adopted new accounting guidance in 2015 related to the accounting for deferred loan costs directly related to the Company’s senior notes, which resulted in the reclassification of the net carrying amount of such costs from a noncurrent asset to a direct deduction from the carrying amount of the related long-term debt on the Company’s consolidated balance sheet.

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, 2015, 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 19, 2016 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 19, 2016

GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	<u>December 31,</u> <u>2015</u>	<u>December 31,</u> <u>2014</u>
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	\$ 112,974	\$ 142,340
Accounts receivable - oil and gas	71,872	103,858
Accounts receivable - related parties	16	46
Prepaid expenses and other current assets	3,905	3,714
Short-term derivative instruments	142,794	78,391
Total current assets	<u>331,561</u>	<u>328,349</u>
Property and equipment:		
Oil and natural gas properties, full-cost accounting, \$1,817,701 and \$1,465,538 excluded from amortization in 2015 and 2014, respectively	5,424,342	3,923,154
Other property and equipment	33,171	18,344
Accumulated depletion, depreciation, amortization and impairment	<u>(2,829,110)</u>	<u>(1,050,879)</u>
Property and equipment, net	<u>2,628,403</u>	<u>2,890,619</u>
Other assets:		
Equity investments	242,393	369,581
Long-term derivative instruments	51,088	24,448
Deferred tax asset	74,925	—
Other assets	6,364	6,476
Total other assets	<u>374,770</u>	<u>400,505</u>
Total assets	<u>\$ 3,334,734</u>	<u>\$ 3,619,473</u>
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 265,128	\$ 371,410
Asset retirement obligation - current	75	75
Short-term derivative instruments	437	—
Deferred tax liability	50,697	27,070
Current maturities of long-term debt	179	168
Total current liabilities	<u>316,516</u>	<u>398,723</u>
Long-term derivative instrument	6,935	—
Asset retirement obligation - long-term	26,362	17,863
Deferred tax liability	—	203,195
Long-term debt, net of current maturities	<u>946,084</u>	<u>703,396</u>
Total liabilities	<u>1,295,897</u>	<u>1,323,177</u>
Commitments and contingencies (Notes 15 and 16)		
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, 108,322,250 issued and outstanding in 2015 and 85,655,438 in 2014	1,082	856
Paid-in capital	2,824,303	1,828,602
Accumulated other comprehensive loss	(55,177)	(26,675)
Retained (deficit) earnings	<u>(731,371)</u>	<u>493,513</u>
Total stockholders' equity	<u>2,038,837</u>	<u>2,296,296</u>
Total liabilities and stockholders' equity	<u>\$ 3,334,734</u>	<u>\$ 3,619,473</u>

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
	2015	2014	2013
	(In thousands, except share data)		
Revenues:			
Gas sales	\$ 507,726	\$ 329,254	\$ 21,015
Oil and condensate sales	141,816	247,381	224,129
Natural gas liquid sales	59,448	94,127	17,081
Other income	485	504	528
	709,475	671,266	262,753
Costs and expenses:			
Lease operating expenses	69,475	52,191	26,703
Production taxes	14,740	24,006	26,933
Midstream gathering and processing	138,590	64,467	11,030
Depreciation, depletion and amortization	337,694	265,431	118,880
Impairment of oil and gas properties	1,440,418	—	—
General and administrative	41,967	38,290	22,519
Accretion expense	820	761	717
(Gain) loss on sale of assets	—	(11)	508
	2,043,704	445,135	207,290
(LOSS) INCOME FROM OPERATIONS	(1,334,229)	226,131	55,463
OTHER (INCOME) EXPENSE:			
Interest expense	51,221	23,986	17,490
Interest income	(643)	(195)	(297)
Litigation settlement	—	25,500	—
Insurance proceeds	(10,015)	—	—
Gain on contribution of investments	—	(84,470)	—
Loss (income) from equity method investments	106,093	(139,434)	(213,058)
	146,656	(174,613)	(195,865)
(LOSS) INCOME BEFORE INCOME TAXES	(1,480,885)	400,744	251,328
INCOME TAX (BENEFIT) EXPENSE	(256,001)	153,341	98,136
NET (LOSS) INCOME	\$ (1,224,884)	\$ 247,403	\$ 153,192
NET (LOSS) INCOME PER COMMON SHARE:			
Basic	\$ (12.27)	\$ 2.90	\$ 1.98
Diluted	\$ (12.27)	\$ 2.88	\$ 1.97
Weighted average common shares outstanding - Basic	99,792,401	85,445,963	77,375,683
Weighted average common shares outstanding - Diluted	99,792,401	85,813,182	77,861,646

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

	For the Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Net (loss) income	\$(1,224,884)	\$247,403	\$153,192
Foreign currency translation adjustment	(28,502)	(16,894)	(12,223)
Change in fair value of derivative instruments (1)	—	—	(4,419)
Reclassification of settled contracts (2)	—	—	10,290
Other comprehensive loss	(28,502)	(16,894)	(6,352)
Comprehensive (loss) income	\$(1,253,386)	\$230,509	\$146,840

- (1) Net of \$4.3 million in taxes for the year ended December 31, 2013. No taxes were recorded in the years ended 2015 and 2014.
- (2) Net of \$(0.5) million in taxes for the year ended December 31, 2013. No taxes were recorded in the years ended 2015 and 2014.

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock Shares	Amount	Paid-in Capital (In thousands, except share data)	Accumulated Other Comprehensive Loss	Retained Earnings (Deficit)	Total Stockholders' Equity
Balance at January 1, 2013	67,527,386	\$ 674	\$1,036,245	\$ (3,429)	\$ 92,918	\$ 1,126,408
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	85,177,532	851	1,813,058	(9,781)	246,110	2,050,238
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	85,655,438	856	1,828,602	(26,675)	493,513	2,296,296
Net loss	—	—	—	—	(1,224,884)	(1,224,884)
Other Comprehensive Loss	—	—	—	(28,502)	—	(28,502)
Stock Compensation	—	—	14,359	—	—	14,359
Issuance of Common Stock in public offerings, net of related expenses	22,425,000	224	981,299	—	—	981,523
Issuance of Restricted Stock	236,812	2	(2)	—	—	—
Issuance of Common Stock through exercise of options	5,000	—	45	—	—	45
Balance at December 31, 2015	108,322,250	\$1,082	\$2,824,303	\$(55,177)	\$ (731,371)	\$ 2,038,837

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Cash flows from operating activities:			
Net (loss) income	\$(1,224,884)	\$ 247,403	\$ 153,192
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Accretion of discount - Asset Retirement Obligation	820	761	717
Depletion, depreciation and amortization	337,694	265,431	118,880
Impairment of oil and gas properties	1,440,418	—	—
Stock-based compensation expense	8,616	8,916	6,297
Loss (gain) from equity investments	113,120	(54,171)	(212,714)
Gain on contribution of investments	—	(84,470)	—
Interest income - note receivable	—	(46)	(26)
(Gain) loss on derivative instruments	(83,671)	(121,148)	18,189
Deferred income tax (benefit) expense	(254,493)	122,917	84,951
Amortization of loan commitment fees	3,219	1,685	1,012
Amortization of note discount and premium	(2,165)	(533)	298
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable	31,986	(45,034)	(33,209)
Decrease in accounts receivable - related party	30	2,571	32,231
Increase in prepaid expenses	(191)	(1,133)	(1,075)
Increase in other assets	—	—	(4,523)
(Decrease) increase in accounts payable and accrued liabilities	(47,199)	73,925	29,310
Settlement of asset retirement obligation	(1,121)	(7,201)	(2,465)
Net cash provided by operating activities	<u>322,179</u>	<u>409,873</u>	<u>191,065</u>
Cash flows from investing activities:			
Deductions to cash held in escrow	8	8	8
Additions to other property and equipment	(13,572)	(7,030)	(2,322)
Additions to oil and gas properties	(1,579,129)	(1,329,277)	(808,183)
Proceeds from sale of other property and equipment	—	—	113
Proceeds from sale of oil and gas properties	27,998	4,404	—
Repayments (advances) on note receivable to related party	—	875	(875)
Proceeds from sale of investments	—	258,362	192,737
Contributions to equity method investments	(14,472)	(63,999)	(47,014)
Distributions from equity method investments	4,914	—	1,276
Net cash used in investing activities	<u>(1,574,253)</u>	<u>(1,136,657)</u>	<u>(664,260)</u>
Cash flows from financing activities:			
Principal payments on borrowings	(350,172)	(115,690)	(149)
Borrowings on line of credit	250,000	215,000	—
Proceeds from bond issuance	350,000	318,000	—
Debt issuance costs and loan commitment fees	(8,688)	(7,831)	(1,283)
Proceeds from issuance of common stock, net of offering costs and exercise of stock options	981,568	689	766,495
Net cash provided by financing activities	<u>1,222,708</u>	<u>410,168</u>	<u>765,063</u>
Net (decrease) increase in cash and cash equivalents	(29,366)	(316,616)	291,868
Cash and cash equivalents at beginning of period	142,340	458,956	167,088
Cash and cash equivalents at end of period	<u>\$ 112,974</u>	<u>\$ 142,340</u>	<u>\$ 458,956</u>
Supplemental disclosure of cash flow information:			
Interest payments	\$ 59,736	\$ 28,646	\$ 24,280
Income tax payments	\$ 16,156	\$ 23,800	\$ 2,761
Supplemental disclosure of non-cash transactions:			
Capitalized stock based compensation	\$ 5,743	\$ 5,944	\$ 4,198
Asset retirement obligation capitalized	\$ 8,800	\$ 9,295	\$ 3,556
Interest capitalized	\$ 13,580	\$ 9,687	\$ 7,132
Foreign currency translation loss on investment in Grizzly Oil Sands ULC	\$ (28,502)	\$ (16,894)	\$ (12,223)

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2015, 2014 AND 2013

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 and along the Louisiana Gulf Coast. The Company also has an interest in producing properties in Northwestern Colorado in the Niobrara Formation and in Western North Dakota in the Bakken 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, Puma Resources, Inc. and Gulfport Buckeye LLC. 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, 2015 and December 31, 2014.

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 2015, 2014 and 2013, 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. Ceiling test impairment can result in 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. As a result of the decline in commodity prices, the Company recognized a ceiling test impairment of \$1.4 billion for the year ended December 31, 2015. If prices of oil, natural gas and natural gas liquids continue to decline, the Company may be required to further write down the value of its oil and natural gas properties, which could negatively affect its results of operations.

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 \$1.8 billion and \$1.5 billion at December 31, 2015 and December 31, 2014, 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 Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“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 loss.

	(In thousands)
December 31, 2012	\$ 2,442
December 31, 2013	\$ (9,781)
December 31, 2014	\$(26,675)
December 31, 2015	\$(55,175)

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 11.

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 basis of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized as income in the year in which realization becomes determinable. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The Company is subject to U.S. federal income tax as well as income tax of multiple jurisdictions. The Company's 1998 – 2015 U.S. federal and state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2015, 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, 2015, 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, 2015 and 2014, 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 FASB ASC 825, "*Financial Instruments*," the Company 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 was multiplied by the total shares owned by the Company and the resulting gain or loss was recognized in loss (income) from equity method investments in the consolidated statements of operations. As of December 31, 2015 and 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. For the year ended December 31, 2015, the Company recognized impairment charges of \$101.6 million related to its investment in Grizzly Oil Sands ULC. At December 31, 2014, the Company recognized an impairment of \$12.1 million related to its investment in Tatex Thailand III, LLC. See Note 4 for further discussion of these impairments.

Accounting for Stock-Based Compensation

The Company accounts for stock-based compensation in accordance with the provisions of FASB ASC 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 Company has not granted any options since 2005, and, at December 31, 2015, there were no options outstanding. The vesting periods for restricted shares range between two to five years with either quarterly or annual vesting installments.

Derivative Instruments

The Company utilizes commodity derivatives to manage the price risk associated with forecasted sale of its natural gas, crude oil and natural gas liquid production. 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 accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. While the Company has historically designated derivative instruments as accounting hedges, effective January 1, 2015, the Company discontinued hedge accounting prospectively. The Company’s current commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

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 2015, the FASB issued Accounting Standard Update (“ASU”) No. 2015-02, “*Consolidation (Topic 810): Amendments to the Consolidation Analysis*.” This ASU provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporation and securitization structure, should be consolidated. The ASU is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. The ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. The Company is in the process of evaluating the impact on its consolidated financial statements. This evaluation could result in certain of the Company’s equity investments being accounted for as variable interest entities.

In April 2015, the FASB issued ASU No. 2015-03, “*Simplifying the Presentation of Debt Issuance Costs (ASU 2015-03)*.” To simplify presentation of debt issuance costs, ASU 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. ASU 2015-03 is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. The Company has reclassified \$17.9 million and \$12.9 million of debt issuance costs to offset long-term debt at December 31, 2015 and 2014, respectively, as shown in Note 6.

In September 2015, the FASB issued ASU No. 2015-16, “*Simplifying the Accounting for Measurement-Period Adjustments*.” The guidance eliminates the requirement to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated. Measurement period adjustments are calculated as if they were known at the acquisition date, but are recognized in the reporting period in which they are determined. Additional disclosures are required about the impact on current-period income statement line items of adjustments that would have been recognized in prior periods if prior-period information had been revised. The guidance is effective for annual periods beginning after December 15, 2015 and is to be applied prospectively to adjustments of provisional amounts that occur after the effective date. Early adoption is permitted. The Company is in the process of evaluating this new guidance and does not expect it to have a material impact on its consolidated financial statements.

In November 2015, the FASB issued ASU No. 2015-17, “*Balance Sheet Classification of Deferred Taxes (Topic 705)*.” Current guidance requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. Deferred tax liabilities and assets are classified as current or noncurrent based on the classification of the related asset or liability for financial reporting. Deferred tax liabilities and assets that are not related to an asset or liability for financial reporting are classified according to the expected reversal date of the temporary difference. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred income tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This update is effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. Earlier application is permitted for all entities as of the beginning of an interim or annual reporting period. The Company is in the process of evaluating the impact on its consolidated financial statements.

In April 2014, the FASB issued 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 was 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; however, in July 2015 the FASB decided to defer the effective date by one year (until

2018) by issuing ASU No. 2015-14, “Revenue From Contracts with Customers: Deferral of the Effective Date.” 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.

2. ACQUISITIONS

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 13 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>

In April 2015, the Company entered into an agreement to acquire Paloma Partners III, LLC (“Paloma”) for a total purchase price of approximately \$301.9 million, subject to certain adjustments. Paloma holds approximately 24,000 net nonproducing acres in the Utica Shale of Ohio. In accordance with the agreement, the Company deposited \$75.0 million into an escrow account. At the closing of the transaction the deposit was credited toward the purchase price. This transaction closed on August 31, 2015 for a purchase price of approximately \$302.3 million, net of purchase price adjustments. At closing, approximately \$30.1 million of the purchase price was placed in escrow as security to the Company for potential indemnification claims that may occur as a result of the sale.

On June 9, 2015, the Company completed the acquisition of 6,198 gross and net acres located in Belmont and Jefferson Counties, Ohio from American Energy-Utica, LLC (“AEU”) for a purchase price of approximately

\$68.2 million, subject to adjustment. On June 12, 2015, the Company completed the acquisition of 38,965 gross (27,228 net) acres located in Monroe County, Ohio, 14.6 MMcf per day of average net production (estimated for April 2015), 18 gross (11.3 net) drilled but uncompleted wells, an 11 mile gas gathering system and a four well pad location from AEU for a total purchase price of approximately \$319.0 million (the "Monroe Acquisition"). On June 29, 2015, the Company acquired an additional 4,950 gross (1,900 net) acres in Monroe County for an additional \$18.2 million from AEU. The total purchase price of these transactions (collectively referred to as the "AEU Acquisition"), was approximately \$405.4 million (\$405.0 million net of purchase price adjustments). At closing, approximately \$67.1 million of the purchase price was placed in escrow pending completion of title review after the closing. In December 2015, approximately \$2.4 million of the escrow was released and returned to the Company as a result of preliminary title review.

The AEU 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 June 12, 2015 acquisition date. The fair value of the assets and liabilities acquired was estimated using assumptions that represent Level 3 inputs. See Note 13 for additional discussion of the measurement inputs.

The Company estimated that the consideration paid in the AEU 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 AEU Acquisition to acquire the properties and the fair value amount of the assets acquired as of June 12, 2015. Both the consideration paid and the fair value assigned to the assets is preliminary and subject to adjustment upon final closing.

	(In thousands)
Consideration paid	
Cash, net of purchase price adjustments	\$405,029
Fair value of identifiable assets acquired	
Oil and natural gas properties	
Proved	\$ 70,804
Unevaluated	334,225
Fair value of net identifiable assets acquired	<u>\$405,029</u>

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2015 and 2014 are as follows:

	December 31,	
	2015	2014
	(In thousands)	
Oil and natural gas properties	\$ 5,424,342	\$ 3,923,154
Office furniture and fixtures	12,589	10,752
Building	16,915	5,398
Land	3,667	2,194
Total property and equipment	5,457,513	3,941,498
Accumulated depletion, depreciation, amortization and impairment	(2,829,110)	(1,050,879)
Property and equipment, net	<u>\$ 2,628,403</u>	<u>\$ 2,890,619</u>

At December 31, 2015, the net book value of the Company's oil and natural gas properties was above the calculated ceiling as a result of the reduced commodity prices during the year ended December 31, 2015. As a

result, the Company recorded an impairment of its oil and natural gas properties under the full cost method of accounting in the amount of \$1.4 billion for the year ended December 31, 2015. No impairment of oil and natural gas properties was required under the ceiling test for the years ended December 31, 2014 or 2013.

Included in oil and natural gas properties at December 31, 2015 and 2014 is the cumulative capitalization of \$100.6 million and \$72.7 million, respectively, 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 \$27.9 million, \$25.2 million and \$14.9 million for the years ended December 31, 2015, 2014 and 2013, respectively.

The following is a summary of Gulfport's oil and gas properties not subject to amortization as of December 31, 2015:

	Costs Incurred in				Total
	2015	2014	2013	Prior to 2013	
	(in thousands)				
Acquisition costs	\$621,519	\$361,167	\$273,146	\$522,872	\$1,778,704
Exploration costs	—	—	—	—	—
Development costs	28,833	4,688	1,436	457	35,414
Capitalized interest	3,674	(2,353)	2,262	—	3,583
Total oil and gas properties not subject to amortization	<u>\$654,026</u>	<u>\$363,502</u>	<u>\$276,844</u>	<u>\$523,329</u>	<u>\$1,817,701</u>

The following table summarizes the Company's non-producing properties excluded from amortization by area as of December 31, 2015:

	<u>December 31, 2015</u>
	(In thousands)
Utica	\$1,812,256
Niobrara	4,932
Southern Louisiana	372
Bakken	96
Other	45
	<u>\$1,817,701</u>

As of December 31, 2014, approximately \$1.5 billion of non-producing leasehold costs was not subject to amortization.

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 typically occurs within three to five years. However, the majority of the Company's non-producing leases have five year extension terms which could extend this time frame beyond five years.

A reconciliation of the Company's asset retirement obligation for the years ended December 31, 2015 and 2014 is as follows:

	<u>December 31,</u>	
	<u>2015</u>	<u>2014</u>
	(In thousands)	
Asset retirement obligation, beginning of period	\$17,938	\$15,083
Liabilities incurred	8,800	9,295
Liabilities settled	(1,121)	(7,201)
Accretion expense	820	761
Asset retirement obligation as of end of period	<u>26,437</u>	<u>17,938</u>
Less current portion	<u>75</u>	<u>75</u>
Asset retirement obligation, long-term	<u><u>\$26,362</u></u>	<u><u>\$17,863</u></u>

4. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2015 and 2014:

	Approximate Ownership %	<u>Carrying Value</u>		<u>Loss (income) from equity method investments</u>		
		<u>December 31,</u>		<u>For the Year Ended December 31,</u>		
		<u>2015</u>	<u>2014</u>	<u>2015</u>	<u>2014</u>	<u>2013</u>
		(In thousands)				
Investment in Tatex Thailand II, LLC	23.5%	\$ —	\$ —	\$ 189	\$ (475)	\$ (343)
Investment in Tatex Thailand III, LLC	17.9%	—	—	—	12,408	254
Investment in Grizzly Oil Sands ULC	24.9999%	50,645	180,218	115,544	13,159	2,999
Investment in Bison Drilling and Field Services LLC	— %	—	—	—	213	3,533
Investment in Muskie Proppant LLC	— %	—	—	—	371	1,975
Investment in Timber Wolf Terminals LLC	50.0%	999	1,013	14	9	(6)
Investment in Windsor Midstream LLC	22.5%	27,955	13,505	(18,398)	(477)	(1,125)
Investment in Stingray Pressure Pumping LLC	— %	—	—	—	2,027	(818)
Investment in Stingray Cementing LLC	50.0%	2,487	2,647	147	344	93
Investment in Blackhawk Midstream LLC	48.5%	—	—	(7,216)	(84,787)	673
Investment in Stingray Logistics LLC	— %	—	—	—	(464)	51
Investment in Diamondback Energy, Inc.	— %	—	—	—	(79,654)	(220,129)
Investment in Stingray Energy Services LLC	50.0%	5,908	5,718	557	(88)	(215)
Investment in Sturgeon Acquisitions LLC	25.0%	22,769	22,507	(1,229)	(1,819)	—
Investment in Mammoth Energy Partners LP	30.5%	131,630	143,973	16,485	(201)	—
		<u>\$242,393</u>	<u>\$369,581</u>	<u>\$106,093</u>	<u>\$(139,434)</u>	<u>\$(213,058)</u>

The tables below summarize financial information for the Company's equity investments, excluding Diamondback, as of December 31, 2015 and 2014.

Summarized balance sheet information:

	<u>December 31,</u>	
	<u>2015</u>	<u>2014</u>
	(In thousands)	
Current assets	\$ 105,537	\$ 181,060
Noncurrent assets	\$1,293,925	\$1,306,891
Current liabilities	\$ 56,559	\$ 114,506
Noncurrent liabilities	\$ 155,995	\$ 230,062

Summarized results of operations:

	December 31,		
	2015	2014	2013
	(In thousands)		
Gross revenue	\$430,729	\$390,620	\$162,401
Net (income) loss	\$(16,761)	\$140,796	\$ 17,350

Gross revenue and net loss presented above for 2014 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.

Tatex Thailand III, LLC

The Company has an ownership interest in Tatex Thailand III, LLC (“Tatex III”). Tatex III previously owned a concession covering approximately 245,000 acres in Southeast Asia. The Company paid cash calls of \$1.6 million during the year ended December 31, 2014. As of December 31, 2014, the Company reviewed its investment in Tatex III and, together with Tatex III, made the decision to allow the concession to expire in January 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 loss (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, 2015, 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. In April 2015, Grizzly determined to cease bitumen production at its Algar Lake facility due to the level of commodity prices. Grizzly continues to monitor market conditions as it assesses future plans for the facility. The Company reviewed its investment in Grizzly as of September 30, 2015 and again as of December 31, 2015 for impairment based on FASB ASC 323 due to certain qualitative factors and as such, engaged an independent third party to assist management in determining fair value calculations of its investment. As a result of the calculated fair values and other qualitative factors, the Company concluded that an other than temporary impairment was required under FASB ASC 323, resulting in an aggregate impairment loss of \$101.6 million for the year ended December 31, 2015 which is included in loss (income) from equity method investments in the consolidated statements of operations. If commodity prices continue to decline, further impairment of the investment in Grizzly may result in the future. During the years ended December 31, 2015 and 2014, Gulfport paid \$14.5 million and \$18.8 million, respectively, in cash calls. Grizzly’s functional currency is the Canadian dollar. The Company’s investment in Grizzly was decreased by \$28.5 million, \$16.9 million and \$12.2 million as a result of a foreign currency translation loss for the years ended December 31, 2015, 2014, and 2013, respectively.

Effective October 5, 2012, Grizzly entered into a \$125.0 million revolving credit facility, of which \$57.4 million was outstanding at December 31, 2015. Grizzly has agreed to pay the outstanding balance by the maturity date of June 2016, of which Gulfport's share is approximately \$14.4 million.

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 year ended December 31, 2014, the Company paid \$17.0 million in cash calls.

The Company contributed its investment in Bison to Mammoth during the fourth quarter of 2014. See below under *Mammoth Energy Partners LP* for information regarding this 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 year ended December 31, 2014, the Company paid \$1.0 million in cash calls to Muskie. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

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 information regarding this contribution.

Timber Wolf Terminals LLC

During 2012, the Company invested in Timber Wolf Terminals LLC ("Timber Wolf"). Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. During the year ended December 31, 2015, the Company paid no cash calls to Timber Wolf. During the year ended December 31, 2014, Gulfport paid an immaterial amount of cash calls.

Windsor Midstream LLC

During 2012, the Company purchased an ownership interest in Windsor Midstream LLC ("Midstream"). Midstream owned a 28.4% interest in Coronado Midstream LLC ("Coronado"), a gas processing plant in West Texas. In March 2015, Coronado was sold to Enlink Midstream Partners, LP ("Enlink") for proceeds of approximately \$600.0 million, consisting of cash and units representing a limited partnership interest in Enlink. Midstream recorded an \$81.6 million gain on the sale of its investment in Coronado. During the year ended December 31, 2015, the Company received \$3.9 million in distributions from Midstream. During the year ended December 31, 2015, the Company paid no cash calls to Midstream. During the year ended December 31, 2014, the Company paid \$2.4 million in cash calls.

Stingray Pressure Pumping LLC

During 2012, the Company invested in Stingray Pressure Pumping LLC ("Stingray Pressure"). Stingray Pressure provides well completion services. During the year ended December 31, 2014, the Company paid \$2.5 million in cash calls. The loss (income) 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 information regarding this 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, 2015 and 2014, the Company did not pay any cash calls related to Stingray Cementing. The loss (income) 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. 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 the first quarter of 2014, which is included as income from equity method investments in the accompanying consolidated statements of operations. During the year ended December 31, 2015, the Company received net proceeds of approximately \$7.2 million from the release of escrow from the Blackhawk sale, which is included in loss (income) from equity investments in the consolidated statements of operations.

Stingray Logistics LLC

During 2012, the Company invested in Stingray Logistics LLC (“Stingray Logistics”). Stingray Logistics provides well services. During the year ended December 31, 2014, 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 information regarding this contribution.

Diamondback Energy, Inc.

On May 7, 2012, the Company entered into a contribution agreement with Diamondback Energy, Inc. (“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. 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 2013, the Company sold an aggregate of 4,534,536 shares of its Diamondback common stock and received aggregate net proceeds of approximately \$192.7 million. In June and September of 2014, the Company sold an aggregate of 2,437,500 shares of its Diamondback common stock 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, 2015 and 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 Company’s ownership interest in Diamondback was below 20% prior to the Company’s sale of its remaining Diamondback common stock in November 2014, the Company had appointed a member of Diamondback’s Board. 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 a gain of approximately \$79.7 million and \$220.1 million on its investment in Diamondback for years ended December 31, 2014 and 2013, respectively, which is included as loss (income) from equity method investments in the consolidated statements of operations.

The Company has determined that for the 2014 and 2013 periods presented in its consolidated financial statements, Diamondback 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. During 2015, the Company did not own any shares of Diamondback common stock and, as such, Rule 3-09 of Regulation S-X is not applicable and the 2015 consolidated financial statements of Diamondback are not attached.

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, 2015, the Company did not pay any cash calls to Stingray Energy. The loss (income) 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. During the year ended December 31, 2015, the Company received approximately \$1.0 million in distributions from Sturgeon.

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 originally intended to pursue the offering in 2015; however, Mammoth continues to evaluate market conditions and expects to launch the offering when commodity prices have recovered. The Company reviewed its investment in Mammoth at December 31, 2015 and determined no impairment was needed. If commodity prices continue to decline, an impairment of the investment in Mammoth may result in the future.

The Company accounted for the contribution as a sale of financial assets under FASB 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 an 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 13 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.

5. OTHER ASSETS

Other assets consist of the following as of December 31:

	<u>2015</u>	<u>2014</u>
	(In thousands)	
Plugging and abandonment escrow account on the WCBB properties (Note 15)	\$3,089	\$3,097
Certificates of Deposit securing letter of credit	276	275
Prepaid drilling costs	58	483
Loan commitment fees	2,870	2,470
Deposits	34	34
Other	37	117
	<u>\$6,364</u>	<u>\$6,476</u>

6. LONG-TERM DEBT

Long-term debt consisted of the following items as of December 31:

	<u>2015</u>	<u>2014</u>
	(In thousands)	
Revolving credit agreement (1)	\$ —	\$100,000
Building loans (2)	1,653	1,826
7.75% senior unsecured notes due 2020 (3)	600,000	600,000
6.625% senior unsecured notes due 2023 (4)	350,000	—
Net unamortized original issue premium (discount), net (5)	12,493	14,658
Net unamortized debt issuance costs (6)	(17,883)	(12,920)
Construction loan (7)	—	—
Less: current maturities of long term debt	(179)	(168)
Debt reflected as long term	<u>\$946,084</u>	<u>\$703,396</u>

Maturities of long-term debt (excluding premiums, discounts and unamortized debt issuance costs) as of December 31, 2015 are as follows:

	(In thousands)
2016	\$ 179
2017	187
2018	1,287
2019	—
2020	600,000
Thereafter	350,000
Total	<u>\$951,653</u>

(1) On December 27, 2013, the Company entered into an Amended and Restated Credit Agreement with 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 other lenders (The “Amended and Restated Credit Agreement”) that provides for a maximum facility amount of \$1.5 billion. The Amended and Restated Credit Agreement matures on June 6, 2018. The Company’s wholly-owned subsidiaries have guaranteed the obligations of the Company under the Amended and Restated Credit Agreement.

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.

On April 10, 2015, the Company entered into a third amendment to the Amended and Restated Credit Agreement. The third amendment increased the borrowing base from \$450.0 million to \$575.0 million and increased the Company's basket for unsecured debt issuances to \$1.2 billion. The third amendment also made certain changes to the lenders and their respective lending commitments thereunder.

On May 29, 2015, the Company entered into a fourth amendment to the Amended and Restated Credit Agreement. The fourth amendment increased the letter of credit sublimit from \$125.0 million to \$150.0 million. Additionally, the Company received consent from its lenders to incur certain new secured indebtedness, limited to \$30.0 million, to finance the construction of its new Oklahoma City headquarters. The lenders also agreed to waive certain provisions of the Amended and Restated Credit Agreement that may prohibit the construction loan.

On September 18, 2015, the Company entered into a fifth amendment to the Amended and Restated Credit Agreement. The fifth amendment among other things, (a) increased Gulfport's borrowing base from \$575.0 million to \$700.0 million, (b) increased the maximum permitted ratio of net funded debt to EBITDAX from a current level of 3.25 to 1.00 to 4.00 to 1.00, (c) revised Gulfport's letter of credit sublimit from \$150.0 million to the greater of (i) \$150.0 million and (ii) 40% of the borrowing base existing at such time, (d) added an investments basket with a \$100.0 million limitation for investments in joint ventures formed to own and operate midstream assets, (e) revised the limit of the general indebtedness basket from a current limit of \$10.0 million in the aggregate at any time outstanding to a limit equal to the greater of (i) \$10.0 million in the aggregate at any time outstanding and (ii) two percent (2%) of the borrowing base at the time such indebtedness is incurred, (f) added a dispositions basket covering dispositions of contracts (and rights or interests therein or thereunder) or other arrangements constituting a release of natural gas interstate transportation capacity, which dispositions do not (when considered cumulatively, and taken together with other related transactions and contractual arrangements) deprive Gulfport of the benefit of any material portion of Gulfport's mineral interests, and (g) revised the provisions that limit Gulfport's ability to enter into swap contracts. As of December 31, 2015, the Company did not have any outstanding borrowing under the Amended and Restated Credit Agreement. At December 31, 2015, the total availability for future borrowings under Amended and Restated Credit Agreement, after giving effect to an aggregate of \$178.6 million of letters of credit, was \$521.4 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.

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 4.00 to 1.00; 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, 2015.

(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 matured in February 2016 and bore interest at the rate of 5.82% per annum. The new building loan required monthly interest and principal payments of approximately \$22,000 and is collateralized by the Oklahoma City office building and associated land. Subsequently, the loan was refinanced with a new interest rate of 4.00% per annum. The building loan currently matures in December 2018 and requires monthly interest and principal payments of approximately \$20,000. The Company paid the balance of the loan in full subsequent to December 31, 2015.

(3) On October 17, 2012, the Company issued \$250.0 million in aggregate principal amount of senior unsecured notes due 2020 (the “October Notes”) 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 senior unsecured notes due 2020 (the “December Notes”) as additional securities under the senior note indenture. The Company used a portion of the net proceeds from the sale of the October Notes to repay all amounts outstanding at such time under its revolving credit facility. The Company used the remaining net proceeds from the sale of the October Notes and the net proceeds from the sale of the December Notes 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”). The August Notes were issued as additional securities under the senior note indenture. The Company used a portion of the net proceeds from the sale of the August Notes to repay all amounts outstanding at such time under its revolving credit facility. The Company used the remaining net proceeds from the sale of the August Notes for general corporate purposes, including funding a portion of its 2014 and 2015 capital development plans. The October Notes, December Notes and the August Notes are collectively referred to as the “2020 Notes”.

In connection with the issuance of the 2020 Notes, the Company and the subsidiary guarantors entered into registration rights agreements with the initial purchasers, pursuant to which the Company and the subsidiary guarantors agreed to file a registration statement with respect to an offer to exchange the 2020 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the October Notes and the December Notes was completed in October 2013 and the exchange offer for the August Note was completed in March 2015.

Under the senior note indenture relating to the 2020 Notes, interest on the 2020 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 2020 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 2020 Notes; provided, however, that the 2020 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 2020 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 2020 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 2020 Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the 2020 Notes initially issued remains outstanding immediately after such redemption.

(4) On April 21, 2015, the Company issued \$350.0 million in aggregate principal amount of 6.625% Senior Notes due 2023 (the “2023 Notes” and, together with the “2020 Notes,” the “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 “2023 Notes Offering”). The Company received net proceeds of approximately \$343.6 million after initial purchaser discounts and commissions and estimated offering expenses.

The 2023 Notes were issued under an indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee. Pursuant to the indenture relating to the 2023 Notes, interest on the 2023 Notes will accrue at a rate of 6.625% per annum on the outstanding principal amount thereof from April 21, 2015, payable semi-annually on May 1 and November 1 of

each year, commencing on November 1, 2015. The 2023 Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of the Company's future unrestricted subsidiaries.

In connection with the 2023 Notes Offering, the Company and its subsidiary guarantors entered into a registration rights agreement, dated as of April 21, 2015, pursuant to which the Company agreed to file a registration statement with respect to an offer to exchange the 2023 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the 2023 Notes was completed on October 13, 2015.

(5) 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 April Notes were issued at par. The premium and discount are being amortized using the effective interest method.

(6) In accordance with ASU 2015-03, loan issuance cost related to the Notes have been presented as a reduction to the Notes. At December 31, 2015, total unamortized debt issuance costs were \$5.1 million for the October Notes, \$1.1 million for the December Notes, \$4.9 million for the August Notes and \$6.8 million for the April Notes.

(7) On June 4, 2015, the Company entered into a construction loan agreement (the "Construction Loan") with InterBank for the construction of a new corporate headquarters in Oklahoma City. The Construction Loan allows for maximum principal borrowings of \$24.5 million and requires the Company to fund 30% of the cost of the construction before any funds can be drawn, which occurred in January 2016. Interest accrues daily on the outstanding principal balance at a fixed rate of 4.50% per annum and is payable on the last day of the month through May 31, 2017. Monthly interest and principal payments are due beginning June 30, 2017, with the final payment due June 4, 2025. As of December 31, 2015, the Company had no borrowings on the Construction Loan.

Interest Expense

The following schedule shows the components of interest expense for the year ended December 31:

	<u>2015</u>	<u>2014</u>	<u>2013</u>
	(In thousands)		
Cash paid for interest	\$ 59,736	\$28,646	\$24,270
Change in accrued interest	4,011	3,875	(969)
Capitalized interest	(13,580)	(9,687)	(7,132)
Amortization of loan costs	3,219	1,685	1,012
Amortization of note discount and premium	(2,165)	(533)	298
Other	—	—	11
Total interest expense	<u>\$ 51,221</u>	<u>\$23,986</u>	<u>\$17,490</u>

The Company capitalized approximately \$13.3 million and \$9.7 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2015 and 2014, respectively. During the year ended December 31, 2015, the Company also capitalized approximately \$0.3 million in interest expense related to building construction.

7. COMMON STOCK OPTIONS, 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, 2015, 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, 2015, the Company had granted 610,966 shares of restricted stock under the 2013 Plan.

Sale of Common Stock

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 used the net proceeds from this equity offering for general corporate purposes, which included expenditures associated with its 2014 drilling program and additional acreage acquisitions in the Utica Shale.

On April 21, 2015, the Company issued 10,925,000 shares of its common stock in an underwritten public offering. The net proceeds from this equity offering were approximately \$501.8 million after underwriting discounts and commissions and offering expenses. The Company used a portion of these net proceeds, together with a portion of the net proceeds from its concurrent senior notes offering (see Note 6), to repay all amounts outstanding at that time under its revolving credit facility and to fund the acquisition of Paloma (see Note 2) and used the remaining net proceeds from these offerings for general corporate purposes, including the funding of a portion of its 2015 capital development plans.

On June 12, 2015, the Company issued 11,500,000 shares of its common stock in an underwritten public offering. The net proceeds from this equity offering were approximately \$479.7 million after underwriting discounts and commissions and offering expenses. The Company used a portion of the net proceeds to fund the Monroe Acquisition (see Note 2) and used the remaining funds for general corporate purposes, including the funding of a portion of its 2015 capital development plans.

8. STOCK-BASED COMPENSATION

During the years ended December 31, 2015, 2014 and 2013 the Company's stock-based compensation cost was \$14.4 million, \$14.9 million and \$10.5 million, respectively, of which the Company capitalized \$5.7 million, \$5.9 million and \$4.2 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, 2015, 2014 and 2013.

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, 2015, 2014 and 2013 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Options outstanding at January 1, 2013	335,241	\$ 6.37	<u>2.39</u>	<u>\$10,678</u>
Granted	—	—		
Exercised	(125,000)	11.20		4,797
Forfeited/expired	<u>—</u>	<u>—</u>		
Options outstanding at December 31, 2013	210,241	3.50	<u>1.07</u>	<u>\$12,538</u>
Granted	—	—		
Exercised	(205,241)	3.36		12,822
Forfeited/expired	<u>—</u>	<u>—</u>		
Options outstanding at December 31, 2014	5,000	9.07	<u>0.69</u>	<u>\$ 163</u>
Granted	—	—		
Exercised	(5,000)	9.07		124
Forfeited/expired	<u>—</u>	<u>—</u>		
Options outstanding at December 31, 2015	<u>—</u>	<u>\$ —</u>	<u>—</u>	<u>\$ —</u>
Options exercisable at December 31, 2015	<u>—</u>	<u>\$ —</u>	<u>—</u>	<u>\$ —</u>

The following table summarizes restricted stock activity for the twelve months ended December 31, 2015, 2014 and 2013:

	<u>Number of Unvested Restricted Shares</u>	<u>Weighted Average Grant Date Fair Value</u>
Unvested shares as of January 1, 2013	245,831	\$31.88
Granted	463,952	50.00
Vested	(237,646)	41.79
Forfeited	<u>(8,500)</u>	<u>38.54</u>
Unvested shares as of December 31, 2013	<u>463,637</u>	<u>\$44.80</u>
Granted	246,409	\$65.07
Vested	(272,665)	45.76
Forfeited	<u>(50,136)</u>	<u>53.72</u>
Unvested shares as of December 31, 2014	<u>387,245</u>	<u>\$55.87</u>
Granted	352,605	\$35.99
Vested	(236,812)	52.39
Forfeited	<u>(18,799)</u>	<u>45.21</u>
Unvested shares as of December 31, 2015	<u>484,239</u>	<u>\$43.51</u>

Unrecognized compensation expense as of December 31, 2015 related to outstanding stock options and restricted shares was \$15.7 million. The expense is expected to be recognized over a weighted average period of 1.55 years.

9. 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, 2015, the carrying value of the outstanding debt represented by the Notes was \$944.6 million, including the remaining unamortized discount of approximately \$2.5 million related to the October Notes and the remaining unamortized premium of approximately \$0.3 million related to the December Notes and approximately \$14.7 million related to the August Notes. Also, included in the carrying value of the Notes are unamortized debt issuance cost of approximately \$5.1 million related to the October Notes, approximately \$1.1 million related to the December Notes, approximately \$4.9 million related to the August Notes, and approximately \$6.8 million related to the April Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately \$846.9 million at December 31, 2015.

10. INCOME TAXES

The income tax provision consists of the following:

	<u>2015</u>	<u>2014</u>	<u>2013</u>
	(In thousands)		
Current:			
State	\$ (1,069)	\$ 14,384	\$ 6,860
Federal	(439)	16,039	6,325
Deferred:			
State	(14,218)	4,314	7,385
Federal	(240,275)	118,604	77,566
Total income tax (benefit) expense provision	<u>\$ (256,001)</u>	<u>\$ 153,341</u>	<u>\$ 98,136</u>

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

	<u>2015</u>	<u>2014</u>	<u>2013</u>
	(In thousands)		
(Loss) income before federal income taxes	\$(1,480,885)	\$400,744	\$251,328
Expected income tax at statutory rate	(518,310)	140,259	87,965
State income taxes	(15,908)	11,570	9,297
Other differences	(420)	1,512	874
Changes in valuation allowance	278,637	—	—
Income tax (benefit) expense recorded	<u>\$ (256,001)</u>	<u>\$ 153,341</u>	<u>\$ 98,136</u>

The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2015, 2014 and 2013 are estimated as follows:

	<u>2015</u>	<u>2014</u>	<u>2013</u>
	(In thousands)		
Deferred tax assets:			
Net operating loss carryforward	\$ 46,209	\$ 1,091	\$ 1,462
Oil and gas property basis difference	292,838	—	—
FASB ASC 718 compensation expense	1,922	1,562	634
AMT credit	23,629	24,053	7,968
Charitable contributions carryover	146	150	25
Unrealized loss on hedging activities	—	—	8,540
Foreign tax credit carryforwards	2,074	2,074	2,074
Accrued liabilities	—	1,260	—
ARO liability	9,415	—	—
State net operating loss carryover	4,344	2,627	4,408
Total deferred tax assets	380,577	32,817	25,111
Valuation allowance for deferred tax assets	(281,782)	(3,145)	(4,743)
Deferred tax assets, net of valuation allowance	98,795	29,672	20,368
Deferred tax liabilities:			
Oil and gas property basis difference	—	183,767	72,173
Investment in pass through entities	7,430	38,315	8,799
Non-oil and gas property basis difference	715	849	249
Investment in nonconsolidated affiliates	—	—	46,495
Unrealized gain on hedging activities	66,422	37,006	—
Total deferred tax liabilities	74,567	259,937	127,716
Net deferred tax asset (liability)	<u>\$ 24,228</u>	<u>\$(230,265)</u>	<u>\$(107,348)</u>

The Company has an available federal tax net operating loss carryforward estimated at approximately \$132.0 million as of December 31, 2015. This carryforward will begin to expire in the year 2035. Based upon the December 31, 2015 net deferred tax asset position and a significant loss in 2015, management believes that there is sufficient negative evidence to place a valuation allowance on the net deferred tax asset that may not be utilized based upon a more likely than not basis. The Company also has state net operating loss carryovers of \$88.6 million that will begin to expire in 2016, alternative minimum tax credits of \$23.6 million with no expiration date and federal foreign tax credit carryovers of \$2.1 million which begin to expire in 2017. The Company believes that it can utilize an Oklahoma state NOL as well as a portion of the AMT credit through carrybacks and a refundable election. Therefore, the Company has recorded a total valuation allowance of \$281.8 million related to the remaining net deferred tax asset.

In 2013, the Company's sale of Diamondback common shares generated a \$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 Company's sale of its remaining shares of Diamondback common stock, as well as its share of the proceeds from Blackhawk's sale of its interest in Ohio Gas Gathering Company, LLC and Ohio Condensate Company, LLC, generated \$203.3 million and \$83.7 million of taxable gain, respectively, resulting in a deferred tax expense of \$79.4 million and \$32.3 million, respectively. The Company's current federal tax benefit in 2015 is primarily attributable to the Company recording a full cost ceiling impairment of \$1.4 billion against the oil and gas assets, while the federal tax expense in 2014 and 2013 is a result of operations plus the sale of Diamondback common shares and the sale of assets by Blackhawk.

At December 31, 2014, the Company owed approximately \$17.7 million for state and federal income taxes payable which is included on the accompanying consolidated balance sheets. No amounts were owed at December 31, 2015.

11. 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,								
	2015			2014			2013		
	Loss	Shares	Per Share	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)								
Basic:									
Net (loss) income	\$(1,224,884)	99,792,401	<u>\$(12.27)</u>	\$247,403	85,445,963	<u>\$2.90</u>	\$153,192	77,375,683	<u>\$1.98</u>
Effect of dilutive securities:									
Stock options and awards	—	—		—	367,219		—	485,963	
Diluted:									
Net (loss) income	<u>\$(1,224,884)</u>	<u>99,792,401</u>	<u>\$(12.27)</u>	<u>\$247,403</u>	<u>85,813,182</u>	<u>\$2.88</u>	<u>\$153,192</u>	<u>77,861,646</u>	<u>\$1.97</u>

There were 449,880 shares of common stock that were considered anti-dilutive for the year ended December 31, 2015. There were no potential shares of common stock that were considered anti-dilutive for the years ended December 31, 2014 and 2013.

12. DERIVATIVE INSTRUMENTS

Oil, Natural Gas and Natural Gas Liquids Derivative Instruments

The Company seeks to reduce its exposure to unfavorable changes in oil, natural gas and natural gas liquids prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps and various types of option contracts. These contracts allow the Company to predict

with greater certainty the effective oil, natural gas and natural gas liquids 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.

Fixed price swaps are settled monthly based on differences between the fixed price specified in the contract and the referenced settlement price. When the referenced settlement price is less than the price specified in the contract, the Company receives an amount from the counterparty based on the price difference multiplied by the volume. Similarly, when the referenced settlement price exceeds the price specified in the contract, the Company pays the counterparty an amount based on the price difference multiplied by the volume. The prices contained in these fixed price swaps are based on Argus Louisiana Light Sweet Crude for oil, the NYMEX West Texas Intermediate for oil, the NYMEX Henry Hub for natural gas and Mont Belvieu for propane. Below is a summary of the Company's open fixed price swap positions as of December 31, 2015.

	<u>Location</u>	<u>Daily Volume (Bbls/day)</u>	<u>Weighted Average Price</u>
January 2016 - June 2016	ARGUS LLS	1,500	\$63.03
January 2016 - June 2016	NYMEX WTI	1,000	\$61.40
	<u>Location</u>	<u>Daily Volume (MMBtu/day)</u>	<u>Weighted Average Price</u>
January 2016 - March 2016	NYMEX Henry Hub	415,000	\$ 3.56
April 2016	NYMEX Henry Hub	425,000	\$ 3.52
May 2016 - June 2016	NYMEX Henry Hub	355,000	\$ 3.42
July 2016 - September 2016	NYMEX Henry Hub	375,000	\$ 3.38
October 2016	NYMEX Henry Hub	405,000	\$ 3.33
November 2016 - December 2016	NYMEX Henry Hub	430,000	\$ 3.30
January 2017 - March 2017	NYMEX Henry Hub	317,500	\$ 3.25
April 2017 - June 2017	NYMEX Henry Hub	272,500	\$ 3.31
July 2017 - December 2017	NYMEX Henry Hub	210,000	\$ 3.12
January 2018 - December 2018	NYMEX Henry Hub	160,000	\$ 3.01
January 2019 - March 2019	NYMEX Henry Hub	20,000	\$ 3.37
	<u>Location</u>	<u>Daily Volume (Bbls/day)</u>	<u>Weighted Average Price</u>
January 2016 - December 2016	Mont Belvieu	1,000	\$20.16

The Company sold call options and used the associated premiums to enhance the fixed price for a portion of the fixed price natural gas swaps listed above. Each short call option has an established ceiling price. When the referenced settlement price is above the price ceiling established by these short call options, the Company pays its counterparty an amount equal to the difference between the referenced settlement price and the price ceiling multiplied by the hedged contract volumes.

	<u>Location</u>	<u>Daily Volume (MMBtu/day)</u>	<u>Weighted Average Price</u>
January 2016 - March 2016	NYMEX Henry Hub	75,000	\$3.25
April 2016 - December 2016	NYMEX Henry Hub	95,000	\$3.18
January 2017 - March 2017	NYMEX Henry Hub	20,000	\$2.91

For a portion of the combined natural gas derivative instruments containing fixed price swaps and sold call options, the counterparty has an option to extend the terms an additional twelve months for the period January 2017 through December 2017. These options expire in December 2016. If executed, the Company would have additional fixed price swaps for 30,000 MMBtu per day at a weighted average price of \$3.33 and additional short call options for 30,000 MMBtu per day at a weighted average ceiling price of \$3.33.

In addition, the Company has entered into natural gas basis swap positions, which settle on the pricing index to basis differential of MichCon or Tetco M2 to the NYMEX Henry Hub natural gas price. As of December 31, 2015, the Company's had the following natural gas basis swap positions for MichCon and Tetco M2, respectively.

	<u>Location</u>	<u>Daily Volume (MMBtu/day)</u>	<u>Weighted Average Price</u>
January 2016 - March 2016	MichCon	70,000	\$ 0.11
April 2016 - December 2016	MichCon	40,000	\$ 0.02
November 2016 - March 2017	Tetco M2	50,000	\$(0.59)

Balance sheet presentation

The Company reports the fair value of derivative instruments on the consolidated balance sheets as derivative instruments under current assets, noncurrent assets, current liabilities, and noncurrent liabilities on a gross basis. The Company determines the current and noncurrent classification based on the timing of expected future cash flows of individual trades. The following table presents the fair value of the Company's derivative instruments on a gross basis at December 31, 2015 and 2014:

	<u>December 31,</u>	
	<u>2015</u>	<u>2014</u>
	(In thousands)	
Short-term derivative instruments - asset	\$142,794	\$78,391
Long-term derivative instruments - asset	\$ 51,088	\$24,448
Short-term derivative instruments - liability	\$ 437	\$ —
Long-term derivative instruments - liability	\$ 6,935	\$ —

Gains and losses

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. The Company has no cash flow hedges in place for the year ended December 31, 2015 and 2014, as all fixed price swaps, swaptions and basis swaps had either been deemed ineffective at their inception or had been accounted for using the mark-to-market accounting method. Amounts reclassified out of accumulated other comprehensive (loss) income as a reduction to oil and condensate sales for the year ended December 31, 2013 were approximately \$9.8 million.

At December 31, 2015 and 2014, no amounts related to fixed price swaps, swaptions or basis swaps remain in accumulated other comprehensive income (loss).

The following table presents the gain and loss recognized in gas sales, oil and condensate sales and natural gas liquids sales in the accompanying consolidated statements of operations due to the change in fair value of derivative instruments for the years ended December 31, 2015, 2014, and 2013.

	<u>Gain (loss) on derivative instruments</u>		
	<u>For the Year Ended December 31,</u>		
	<u>2015</u>	<u>2014</u>	<u>2013</u>
	(In thousands)		
Gas sales	\$72,412	\$115,324	\$(12,484)
Oil and condensate sales	10,149	5,824	(5,705)
Natural gas liquids sales	1,110	—	—
Total	<u>\$83,671</u>	<u>\$121,148</u>	<u>\$(18,189)</u>

The \$18.2 million loss in 2013 was comprised of \$9.1 million related to hedge ineffectiveness and \$9.1 million related to amortization of other comprehensive income.

The Company delivered approximately 46% of its 2015 production under fixed price swaps.

Concentration of Credit Risk

By using derivative instruments that are not traded on an exchange, the Company is exposed to the credit risk of its counterparties. Credit risk is the risk of loss from counterparties not performing under the terms of the derivative instrument. When the fair value of a derivative instrument is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The Company's derivative contracts are with multiple counterparties to lessen its exposure to any individual counterparty. Additionally, the Company uses master netting agreements to minimize credit risk exposure. The creditworthiness of the Company's counterparties is subject to periodic review. Other than as provided by the Company's revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under its derivative instruments, nor are the counterparties required to provide credit support to the Company.

13. 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, "Fair Value Measurement and Disclosures" ("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.

Valuation techniques that maximize the use of observable inputs are favored. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.

The following tables summarize the Company's financial and non-financial liabilities by FASB ASC 820 valuation level as of December 31, 2015 and 2014:

	December 31, 2015		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	\$—	\$193,882	\$—
Liabilities:			
Derivative Instruments	\$—	\$ 7,372	\$—

December 31, 2014		
Level 1	Level 2	Level 3
(In thousands)		

Assets:

Derivative Instruments	\$—	\$102,839	\$—
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The Company estimates the fair value of all derivative instruments industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data.

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 3 for further discussion of the Company’s asset retirement obligations. Asset retirement obligations incurred during the year ended December 31, 2015 were approximately \$8.8 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’s estimated fair value of the investment as of the November 24, 2014 contribution date was \$143.5 million. See Note 4 for further discussion of the Company’s contribution to Mammoth.

Due to the unobservable nature of the inputs, the fair value of the Company’s investment in Grizzly was estimated using assumptions that represent Level 3 inputs. The Company estimated the fair value of the investment as of December 31, 2015 to be approximately \$50.6 million. See Note 4 for further discussion of the Company’s investment in Grizzly.

14. RELATED PARTY TRANSACTIONS

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

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 4. As of the contribution date, the Company acquired a 30.5% limited partner interest in Mammoth. No amounts were owed to Stingray Pressure at the date of the contribution. Approximately \$78.3 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.

Stingray Cementing, which is 50% owned by the Company, provides well cementing services as discussed above in Note 4. At December 31, 2015 and 2014, the Company owed Stingray Cementing approximately \$2.1 million and \$0.8 million, respectively, related to these services. Approximately \$7.0 million and \$6.0 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, 2015 and 2014, 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 4. At December 31, 2015 and 2014, the Company owed Stingray Energy approximately \$2.2 million and \$6.0 million, respectively, related to these services. Approximately \$2.2 million and \$1.3 million of services provided by Stingray Energy are included in lease operating expenses in the consolidated statements of operations for the year ended December 31, 2015 and 2014, respectively. Approximately \$16.0 million and \$24.8 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, 2015 and 2014, respectively.

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 4. Approximately \$7.6 million of services provided by Panther are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2014.

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 and oil and natural gas fracture grade sand. Muskie was previously owned 25% by the Company until its contribution to Mammoth in November 2014, as discussed above in Note 4. As of the contribution date, the Company acquired a 30.5% limited partner interest in Mammoth. No amounts were owed to Muskie as of the date of the contribution. No services provided by Muskie are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2014.

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 4. Approximately \$1.0 million related to services performed by Redback are included in oil and natural gas properties on the accompanying consolidated balance sheets at 2014.

In November 2014, the Company contributed its investment in Muskie, Stingray Pressure, Stingray Logistics and Bison to Mammoth in exchange for a 30.5% limited partner interest in Mammoth. Approximately \$141.2 million and \$11.1 million of services provided by Mammoth are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2015 and 2014, respectively. At December 31, 2015 and 2014, the Company owed Mammoth approximately \$24.7 million and \$28.4 million, respectively, related to these services.

15. 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, 2015, the plugging and abandonment trust totaled approximately \$3.1 million. At December 31, 2015, the Company had plugged 463 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, 2015, 2014 and 2013, Gulfport incurred \$1.4 million, \$0.8 million, and \$0.6 million, respectively, in contributions expense related to this plan.

Employment Agreements

Effective November 1, 2012, the Company entered into employment agreements with Messrs. James Palm, Mike Liddell, and Michael G. Moore, each with an initial three-year term expiring on November 1, 2015 subjected 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 incentive plans and other employee benefits.

Effective February 15, 2014, Gulfport's former Chief Executive Officer, 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, 2015, the minimum commitment under Mr. Palm's separation agreement was approximately \$0.4 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. Mr. Liddell terminated his consulting agreement with the Company effective January 1, 2015.

On April 22, 2014, the Board of Directors appointed Mr. 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. Effective as of April 29, 2015, the Company amended and restated its existing employment agreement with Mr. Moore. The employment agreement, as amended and restated as of April 29, 2015, reflects the decision of the compensation committee of the Company's board of directors to increase Mr. Moore's annual base salary to \$460,000 for 2015 and the determination by the compensation committee to continue to increase Mr. Moore's annual base salary during 2016 and 2017 so as to achieve alignment between the 25th and 50th percentile of the Company's peer group disclosed in the Company's annual proxy statement. The amended and restated employment agreement also eliminated Mr. Moore's right to receive a fixed annual grant of 40,000 shares of restricted stock. Instead, consistent with the recommendation of the Company's compensation consultant and approved by the compensation committee, the amended and restated employment agreement provided that Mr. Moore is entitled to receive an award of restricted stock equal to 500% of his annual base salary on the same vesting schedule as previously provided in his employment agreement with respect to his equity awards.

On March 13, 2015, the Company entered into an employment agreement with Ross Kirtley, the Company's Chief Operating Officer. The agreement has a two-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.

On March 13, 2015, the Company entered into an employment agreement with Aaron Gaydosik, the Company's Chief Financial Officer. The agreement has a three-year term commencing effective August 11, 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 aggregated minimum commitment for future salary at December 31, 2015 under the above listed employment agreements was approximately \$1.2 million.

Firm Transportation Commitments

The Company had approximately 1,452,000 MMBtu per day of firm sales contracted with third parties. The table below presents these commitments at December 31, 2015 as follows:

	(MMBtu per day)
2016	476,000
2017	349,000
2018	216,000
2019	197,000
2020	152,000
Thereafter	62,000
Total	<u>1,452,000</u>

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, 2015 are as follows:

	(In thousands)
2016	\$ 800
2017	583
2018	54
Total	<u>1,437</u>

Presented below is rent expense for the years ended December 31, 2015, 2014 and 2013, respectively.

	<u>For the years ended December 31,</u>		
	<u>2015</u>	<u>2014</u>	<u>2013</u>
	(In thousands)		
Minimum rentals	\$759	\$733	\$258
Less: Sublease rentals	<u>8</u>	<u>15</u>	<u>45</u>
	<u>\$751</u>	<u>\$718</u>	<u>\$213</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, 2015, 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, 2015 are as follows:

	(In thousands)
2016	52,440
2017	52,440
2018	39,330
Total	<u>\$144,210</u>

16. 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.

Insurance Proceeds

In September 2014, the Company settled its legacy surface contamination lawsuit with Reeds et al. Under the terms of the settlement agreement, Gulfport paid \$18.0 million, which is included in litigation settlement in the accompanying consolidated statements of operations for the year ended December 31, 2014. In October 2015, the Company was reimbursed \$10.0 million, net of related legal fees, by its insurance provider which is included in insurance proceeds in the accompanying consolidated statements of operations for the year ended December 31, 2015.

Concentration of Credit Risk

Gulfport operates in the oil and natural 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, 2015, Gulfport held cash in excess of insured limits in these banks totaling \$112.0 million.

During the year ended December 31, 2015, Gulfport sold approximately 90% and 10% of its oil production to Shell Trading Company ("Shell") and Marathon Oil Corporation, respectively, 76% and 24% of its natural gas

liquids production to MarkWest Utica EMG (“Mark West”) and Antero Resources, respectively, and 79%, 14% and 5% of its natural gas production to BP Energy Company (“BP”), DTE Energy Trading Inc. and Hess, respectively. During the year ended December 31, 2014, Gulfport sold approximately 99% of its oil production to Shell, 100% of its natural gas liquids production to MarkWest 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 and 32%, 31%, and 17% of its natural gas production to Sequent Energy Management, L.P., Hess and Interstate Gas Supply Inc., respectively.

17. 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 October Notes, December Notes and the August Notes are collectively referred to as the “2020 Notes”. The 2020 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 2020 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 2020 Notes, the Company and the subsidiary guarantors entered into registration rights agreements with the initial purchasers, pursuant to which the Company and the subsidiary guarantors agreed to file a registration statement with respect to an offer to exchange the 2020 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the October Notes and December Notes was completed in October 2013 and the exchange offer for the August Notes was completed in March 2015.

On April 21, 2015, the Company issued \$350.0 million in aggregate principal amount of its 6.625% Senior Notes due 2023 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. In connection with the April Notes Offering, the Company and its subsidiary guarantors entered into a registration rights agreement, dated as of April 21, 2015, pursuant to which the Company agreed to file a registration statement with respect to an offer to exchange the April Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the April Notes was completed on October 13, 2015.

The following condensed consolidating balance sheets, statements of operations, statements of comprehensive (loss) income 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, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	\$ 112,494	\$ 479	\$ 1	\$ —	\$ 112,974
Accounts receivable - oil and gas	72,241	54	—	(423)	71,872
Accounts receivable - related parties	16	—	—	—	16
Accounts receivable - intercompany	326,475	60	—	(326,535)	—
Prepaid expenses and other current assets	3,905	—	—	—	3,905
Short-term derivative instruments	142,794	—	—	—	142,794
Total current assets	<u>657,925</u>	<u>593</u>	<u>1</u>	<u>(326,958)</u>	<u>331,561</u>
Property and equipment:					
Oil and natural gas properties, full-cost accounting	5,108,258	316,813	—	(729)	5,424,342
Other property and equipment	33,128	43	—	—	33,171
Accumulated depletion, depreciation, amortization and impairment	(2,829,081)	(29)	—	—	(2,829,110)
Property and equipment, net	<u>2,312,305</u>	<u>316,827</u>	<u>—</u>	<u>(729)</u>	<u>2,628,403</u>
Other assets:					
Equity investments and investments in subsidiaries	231,892	—	50,644	(40,143)	242,393
Long-term derivative instruments	51,088	—	—	—	51,088
Deferred tax asset	74,925	—	—	—	74,925
Other assets	6,364	—	—	—	6,364
Total other assets	<u>364,269</u>	<u>—</u>	<u>50,644</u>	<u>(40,143)</u>	<u>374,770</u>
Total assets	<u>\$ 3,334,499</u>	<u>\$317,420</u>	<u>\$ 50,645</u>	<u>\$(367,830)</u>	<u>\$ 3,334,734</u>
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	\$ 264,893	\$ 527	\$ —	\$ (292)	\$ 265,128
Accounts payable - intercompany	—	326,541	124	(326,665)	—
Asset retirement obligation - current	75	—	—	—	75
Short-term derivative instruments	437	—	—	—	437
Deferred tax liability	50,697	—	—	—	50,697
Current maturities of long-term debt	179	—	—	—	179
Total current liabilities	<u>316,281</u>	<u>327,068</u>	<u>124</u>	<u>(326,957)</u>	<u>316,516</u>
Long-term derivative instrument	6,935	—	—	—	6,935
Asset retirement obligation - long-term	26,362	—	—	—	26,362
Long-term debt, net of current maturities	946,084	—	—	—	946,084
Total liabilities	<u>1,295,662</u>	<u>327,068</u>	<u>124</u>	<u>(326,957)</u>	<u>1,295,897</u>
Stockholders' equity:					
Common stock	1,082	—	—	—	1,082
Paid-in capital	2,824,303	322	241,553	(241,875)	2,824,303
Accumulated other comprehensive (loss) income	(55,177)	—	(55,177)	55,177	(55,177)
Retained (deficit) earnings	(731,371)	(9,970)	(135,855)	145,825	(731,371)
Total stockholders' equity	<u>2,038,837</u>	<u>(9,648)</u>	<u>50,521</u>	<u>(40,873)</u>	<u>2,038,837</u>
Total liabilities and stockholders' equity	<u>\$ 3,334,499</u>	<u>\$317,420</u>	<u>\$ 50,645</u>	<u>\$(367,830)</u>	<u>\$ 3,334,734</u>

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	<u>372,670</u>	<u>927</u>	<u>1</u>	<u>(45,249)</u>	<u>328,349</u>
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	<u>2,855,320</u>	<u>36,009</u>	<u>—</u>	<u>(710)</u>	<u>2,890,619</u>
Other assets:					
Equity investments and investments in subsidiaries	360,238	—	180,217	(170,874)	369,581
Long-term derivative instruments	24,448	—	—	—	24,448
Other assets	6,476	—	—	—	6,476
Total other assets	<u>391,162</u>	<u>—</u>	<u>180,217</u>	<u>(170,874)</u>	<u>400,505</u>
Total assets	<u>\$ 3,619,152</u>	<u>\$36,936</u>	<u>\$180,218</u>	<u>\$(216,833)</u>	<u>\$ 3,619,473</u>
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	<u>398,402</u>	<u>45,464</u>	<u>106</u>	<u>(45,249)</u>	<u>398,723</u>
Asset retirement obligation - long-term	17,863	—	—	—	17,863
Deferred tax liability	203,195	—	—	—	203,195
Long-term debt, net of current maturities	703,396	—	—	—	703,396
Total liabilities	<u>1,322,856</u>	<u>45,464</u>	<u>106</u>	<u>(45,249)</u>	<u>1,323,177</u>
Stockholders' equity:					
Common stock	856	—	—	—	856
Paid-in capital	1,828,602	322	227,079	(227,401)	1,828,602
Accumulated other comprehensive (loss) income	(26,675)	—	(26,675)	26,675	(26,675)
Retained earnings (deficit)	493,513	(8,850)	(20,292)	29,142	493,513
Total stockholders' equity	<u>2,296,296</u>	<u>(8,528)</u>	<u>180,112</u>	<u>(171,584)</u>	<u>2,296,296</u>
Total liabilities and stockholders' equity	<u>\$ 3,619,152</u>	<u>\$36,936</u>	<u>\$180,218</u>	<u>\$(216,833)</u>	<u>\$ 3,619,473</u>

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	\$ 709,525	\$1,468	\$ —	\$ (1,518)	\$ 709,475
Costs and expenses:					
Lease operating expenses	68,632	843	—	—	69,475
Production taxes	14,618	122	—	—	14,740
Midstream gathering and processing	138,526	64	—	—	138,590
Depreciation, depletion and amortization	337,689	5	—	—	337,694
Impairment of oil and gas properties	1,440,418	—	—	—	1,440,418
General and administrative	41,892	55	20	—	41,967
Accretion expense	820	—	—	—	820
	<u>2,042,595</u>	<u>1,089</u>	<u>20</u>	<u>—</u>	<u>2,043,704</u>
(LOSS) INCOME FROM OPERATIONS	<u>(1,333,070)</u>	<u>379</u>	<u>(20)</u>	<u>(1,518)</u>	<u>(1,334,229)</u>
OTHER (INCOME) EXPENSE:					
Interest expense	51,221	—	—	—	51,221
Interest income	(643)	—	—	—	(643)
Insurance proceeds	(10,015)	—	—	—	(10,015)
Loss (income) from equity method investments and investments in subsidiaries	107,252	—	115,544	(116,703)	106,093
	<u>147,815</u>	<u>—</u>	<u>115,544</u>	<u>(116,703)</u>	<u>146,656</u>
(LOSS) INCOME BEFORE INCOME TAXES	(1,480,885)	379	(115,564)	115,185	(1,480,885)
INCOME TAX BENEFIT	(256,001)	—	—	—	(256,001)
NET (LOSS) INCOME	<u><u>\$ (1,224,884)</u></u>	<u><u>\$ 379</u></u>	<u><u>\$(115,564)</u></u>	<u><u>\$ 115,185</u></u>	<u><u>\$ (1,224,884)</u></u>

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	153,341	—	—	—	153,341
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
	<u>206,280</u>	<u>1,009</u>	<u>1</u>	<u>—</u>	<u>207,290</u>
INCOME (LOSS) FROM OPERATIONS	<u>55,529</u>	<u>508</u>	<u>(1)</u>	<u>(573)</u>	<u>55,463</u>
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)
	<u>(195,799)</u>	<u>—</u>	<u>2,999</u>	<u>(3,065)</u>	<u>(195,865)</u>
INCOME (LOSS) BEFORE INCOME TAXES	251,328	508	(3,000)	2,492	251,328
INCOME TAX EXPENSE	98,136	—	—	—	98,136
NET INCOME (LOSS)	<u>\$ 153,192</u>	<u>\$ 508</u>	<u>\$(3,000)</u>	<u>\$ 2,492</u>	<u>\$ 153,192</u>

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

	Year Ended December 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	\$(1,224,884)	\$379	\$(115,564)	\$115,185	\$(1,224,884)
Foreign currency translation adjustment	(28,502)	—	(28,502)	28,502	(28,502)
Other comprehensive (loss) income	(28,502)	—	(28,502)	28,502	(28,502)
Comprehensive (loss) income	\$(1,253,386)	\$379	\$(144,066)	\$143,687	\$(1,253,386)

	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 (loss) income	(16,894)	—	(16,894)	16,894	(16,894)
Comprehensive income (loss)	\$ 230,509	\$529	\$ (30,051)	\$ 29,522	\$ 230,509

	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 (loss) income	(6,352)	—	(12,223)	12,223	(6,352)
Comprehensive income (loss)	\$ 146,840	\$508	\$ (15,223)	\$ 14,715	\$ 146,840

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Year Ended December 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	\$ 344,018	\$(21,839)	\$ (2)	\$ 2	\$ 322,179
Net cash (used in) provided by investing activities	(1,595,767)	21,514	(14,472)	14,472	(1,574,253)
Net cash provided by (used in) financing activities	1,222,708	—	14,474	(14,474)	1,222,708
Net decrease in cash and cash equivalents	(29,041)	(325)	—	—	(29,366)
Cash and cash equivalents at beginning of period	141,535	804	1	—	142,340
Cash and cash equivalents at end of period	\$ 112,494	\$ 479	\$ 1	\$ —	\$ 112,974

	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 (used in) provided by 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 (decrease) increase 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 (used in) provided by 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

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

As discussed above in Note 4, the Company did not own any of Diamondback's common stock at December 31, 2015 or December 31, 2014. However, at December 31, 2013, the Company owned a 7.2% equity interest in Diamondback, 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 and 2015.

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

	<u>2015</u>	<u>2014</u>
	(In thousands)	
Proven properties	\$ 3,606,641	\$ 2,457,616
Unproven properties	1,817,701	1,465,538
	<u>5,424,342</u>	<u>3,923,154</u>
Accumulated depreciation, depletion, amortization and impairment reserve	(2,820,113)	(1,044,273)
Net capitalized costs	<u>\$ 2,604,229</u>	<u>\$ 2,878,881</u>
<i>Equity investment in Grizzly Oil Sands ULC</i>		
Proven properties	\$ 81,473	\$ 96,859
Unproven properties	82,388	103,160
	<u>163,861</u>	<u>200,019</u>
Accumulated depreciation, depletion, amortization and impairment reserve	(1,531)	(1,248)
Net capitalized costs	<u>\$ 162,330</u>	<u>\$ 198,771</u>

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	<u>2015</u>	<u>2014</u>	<u>2013</u>
	(In thousands)		
Acquisition	\$ 810,755	\$ 440,288	\$338,153
Development of proved undeveloped properties	642,811	864,511	408,121
Exploratory	—	2,249	26,174
Recompletions	13,894	45,658	44,633
Capitalized asset retirement obligation	8,800	2,095	3,556
Total	<u>\$1,476,260</u>	<u>\$1,354,801</u>	<u>\$820,637</u>
<i>Equity investment in Diamondback Energy, Inc.</i>			
Acquisition	\$ —	\$ —	\$ 44,534
Development of proved undeveloped properties	—	—	6,369
Exploratory	—	—	17,491
Capitalized asset retirement obligation	—	—	50
Total	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 68,444</u>
<i>Equity investment in Grizzly Oil Sands ULC</i>			
Acquisition	\$ 396	\$ 1,230	\$ —
Development of proved undeveloped properties	47	7,107	—
Exploratory	—	—	—
Capitalized asset retirement obligation	282	1,055	—
Total	<u>\$ 725</u>	<u>\$ 9,392</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.

	2015	2014	2013
	(In thousands)		
Revenues	\$ 708,990	\$ 670,762	\$ 262,225
Production costs	(222,805)	(140,664)	(64,666)
Depletion	(335,288)	(263,946)	(118,118)
Impairment	(1,440,418)	—	—
	<u>(1,289,521)</u>	<u>266,152</u>	<u>79,441</u>
Income tax (benefit) expense			
Current	—	—	—
Deferred	(220,201)	96,061	49,447
	<u>(220,201)</u>	<u>96,061</u>	<u>49,447</u>
Results of operations from producing activities	<u>\$(1,069,320)</u>	<u>\$ 170,091</u>	<u>\$ 29,994</u>
Depletion per Mcf of gas equivalent (Mcf)	<u>\$ 1.68</u>	<u>\$ 3.01</u>	<u>\$ 4.78</u>
<i>Results of Operations from equity method investment in Diamondback Energy, Inc.</i>			
Revenues	\$ —	\$ —	\$ 14,976
Production costs	—	—	(2,518)
Depletion	—	—	(4,754)
	—	—	7,704
Income tax expense	—	—	2,286
Results of operations from producing activities	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 5,418</u>
<i>Results of Operations from equity method investment in Grizzly Oil Sands ULC</i>			
Revenues	\$ 1,436	\$ 5,449	\$ —
Production costs	(1,549)	(10,113)	—
Depletion	(625)	(1,195)	—
	(738)	(5,859)	—
Income tax expense	—	—	—
Results of operations from producing activities	<u>\$ (738)</u>	<u>\$ (5,859)</u>	<u>\$ —</u>

Oil and Gas Reserves

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2015, 2014 and 2013 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, 2015, 2014 and 2013, 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 2015 reserve report are \$50.28 per barrel of oil, \$2.59 per MMBtu and \$13.21 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, 2014 and 2013 for reserve report purposes are \$94.99 per barrel, \$4.35 per MMBtu and \$44.84 per barrel for NGLs and \$96.78 per barrel, \$3.67 per MMBtu and \$41.23 per barrel for NGLs, 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.

	2015			2014			2013		
	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)
Proved Reserves									
Beginning of the period	9,497	719,006	26,268	8,346	146,446	5,675	8,106	33,771	145
Purchases in oil and gas reserves in place	—	371,663	—	173	8,863	353	—	—	—
Extensions and discoveries	2,413	997,057	5,486	4,975	629,151	22,594	2,765	123,597	5,850
Revisions of prior reserve estimates	(2,553)	(371,430)	(9,594)	(1,313)	(6,136)	(304)	(208)	(2,031)	—
Current production	(2,899)	(156,151)	(4,424)	(2,684)	(59,318)	(2,050)	(2,317)	(8,891)	(320)
End of period	<u>6,458</u>	<u>1,560,145</u>	<u>17,736</u>	<u>9,497</u>	<u>719,006</u>	<u>26,268</u>	<u>8,346</u>	<u>146,446</u>	<u>5,675</u>
Proved developed reserves	<u>6,120</u>	<u>652,961</u>	<u>12,910</u>	<u>5,719</u>	<u>345,166</u>	<u>12,379</u>	<u>5,609</u>	<u>94,552</u>	<u>3,527</u>
Proved undeveloped reserves	<u>338</u>	<u>907,184</u>	<u>4,826</u>	<u>3,778</u>	<u>373,840</u>	<u>13,889</u>	<u>2,737</u>	<u>51,894</u>	<u>2,148</u>
<i>Equity investment in</i>									
<i>Diamondback Energy, Inc.</i>									
Proved Reserves									
Beginning of the period	—	—	—	—	—	—	5,606	7,398	1,766
Change in ownership interest in Diamondback	—	—	—	—	—	—	(3,720)	(4,909)	(1,171)
Purchases in oil and gas reserves in place	—	—	—	—	—	—	528	752	120
Extensions and discoveries	—	—	—	—	—	—	1,227	1,741	331
Revisions of prior reserve estimates	—	—	—	—	—	—	(428)	(417)	(249)
Current production	—	—	—	—	—	—	(146)	(124)	(26)
End of period	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>3,067</u>	<u>4,441</u>	<u>771</u>
Proved developed reserves	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>1,425</u>	<u>2,263</u>	<u>358</u>
Proved undeveloped reserves	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>1,642</u>	<u>2,178</u>	<u>413</u>
<i>Equity investment in Grizzly Oil Sands ULC</i>									
Beginning of the period	14,558	—	—	13,637	—	—	—	—	—
Purchases in oil and gas reserves in place	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	—	—	—	—	—	—	—	—
Revisions of prior reserve estimates	(14,530)	—	—	990	—	—	—	—	—
Current production	(28)	—	—	(69)	—	—	—	—	—
End of period	<u>—</u>	<u>—</u>	<u>—</u>	<u>14,558</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>
Proved developed reserves	<u>—</u>	<u>—</u>	<u>—</u>	<u>1,632</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>
Proved undeveloped reserves	<u>—</u>	<u>—</u>	<u>—</u>	<u>12,926</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>	<u>—</u>

In 2015, the Company experienced extensions and discoveries of 1,044.5 Bcfe of proved reserves attributable to the continued development of the Company's Utica Shale acreage. In addition, the Company experienced downward revisions of 444,314 MMcfe in estimated proved reserves in 2015 primarily due to the exclusion of PUD locations in our Utica and Southern Louisiana fields that became uneconomic due to the continued decline in commodity prices. In 2015, the Company also purchased 371,663 MMcfe of proved reserves as a result of acquisitions from Paloma and AEU discussed above in Note 2. In 2014, the Company experienced extensions and discoveries of 786,347 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.

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, 2015, 2014 and 2013 using an unweighted average first-of-the-month price for the period January through December 31, 2015, 2014 and 2013.

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

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Future cash flows	\$3,043,450	\$4,667,678	\$1,657,708
Future development and abandonment costs	(877,660)	(719,898)	(272,500)
Future production costs	(941,243)	(880,427)	(274,428)
Future production taxes	(58,169)	(71,229)	(78,647)
Future income taxes	(2,648)	(693,154)	(172,691)
Future net cash flows	1,163,730	2,302,970	859,442
10% discount to reflect timing of cash flows	(399,399)	(875,803)	(280,976)
Standardized measure of discounted future net cash flows	<u>\$ 764,331</u>	<u>\$1,427,167</u>	<u>\$ 578,466</u>
<i>Equity investment in Diamondback Energy, Inc. Standardized measure of discounted cash flows</i>			
Future cash flows	\$ —	\$ —	\$ 331,505
Future development and abandonment costs	—	—	(37,229)
Future production costs	—	—	(58,096)
Future production taxes	—	—	(22,925)
Future income taxes	—	—	(48,547)
Future net cash flows	—	—	164,708
10% discount to reflect timing of cash flows	—	—	(94,462)
Standardized measure of discounted future net cash flows	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 70,246</u>
<i>Equity investment in Grizzly Oil Sands ULC Standardized measure of discounted cash flows</i>			
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>\$ —</u>	<u>\$ 93,746</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 \$170.3 million, \$177.6 million and \$158.4 million during years 2016, 2017 and 2018, respectively.

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

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Sales and transfers of oil and gas produced, net of production costs	\$ (486,185)	\$(530,098)	\$(197,559)
Net changes in prices, production costs, and development costs	(1,412,181)	97,716	65,573
Acquisition of oil and gas reserves in place	83,340	14,266	—
Extensions and discoveries	262,895	790,533	130,826
Previously estimated development costs incurred during the period	117,540	68,227	43,478
Revisions of previous quantity estimates, less related production costs	(98,162)	(37,801)	(3,591)
Accretion of discount	142,717	57,847	34,864
Net changes in income taxes	412,240	(295,226)	(30,239)
Change in production rates and other	314,960	683,237	186,473
Total change in standardized measure of discounted future net cash flows	<u>\$ (662,836)</u>	<u>\$ 848,701</u>	<u>\$ 229,825</u>
<i>Equity investment in Diamondback Energy, Inc. Changes in standardized measure of discounted cash flows</i>			
Change in ownership interest in Diamondback	\$ —	\$ —	\$ (52,145)
Sales and transfers of oil and gas produced, net of production costs	—	—	(12,524)
Net changes in prices, production costs, and development costs	—	—	3,312
Acquisition of oil and gas reserves in place	—	—	21,968
Extensions and discoveries	—	—	39,776
Previously estimated development costs incurred during the period	—	—	5,517
Revisions of previous quantity estimates, less related production costs	—	—	(9,143)
Accretion of discount	—	—	4,175
Net changes in income taxes	—	—	(12,137)
Change in production rates and other	—	—	2,862
Total change in standardized measure of discounted future net cash flows	<u>\$ —</u>	<u>\$ —</u>	<u>\$ (8,339)</u>
<i>Equity investment in Grizzly Oil Sands ULC Changes in standardized measure of discounted cash flows</i>			
Sales and transfers of oil and gas produced, net of production costs	\$ 114	\$ 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	47	—	—
Revisions of previous quantity estimates, less related production costs	(103,282)	10,659	—
Accretion of discount	9,375	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	<u>\$ (93,746)</u>	<u>\$ (55,718)</u>	<u>\$ —</u>

19. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table summarizes quarterly financial data for the years ended December 31, 2015 and 2014:

	2015			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	\$176,317	\$112,270	\$ 230,569	\$ 190,319
Income (loss) from operations	28,773	(21,644)	(529,076)	(812,282)
Income tax expense (benefit)	14,479	(17,214)	(216,603)	(36,663)
Net income (loss)	25,519	(31,325)	(388,209)	(830,869)
Income (loss) per share:				
Basic	<u>\$ 0.30</u>	<u>\$ (0.32)</u>	<u>\$ (3.59)</u>	<u>\$ (7.67)</u>
Diluted	<u>\$ 0.30</u>	<u>\$ (0.32)</u>	<u>\$ (3.59)</u>	<u>\$ (7.67)</u>
	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	<u>\$ 0.97</u>	<u>\$ 0.56</u>	<u>\$ 0.08</u>	<u>\$ 1.29</u>
Diluted	<u>\$ 0.96</u>	<u>\$ 0.56</u>	<u>\$ 0.08</u>	<u>\$ 1.28</u>

20. SUBSEQUENT EVENTS

Derivatives

In January of 2016, the Company entered into fixed price swaps for the period of February 2016 through March 2016, for 45,000 MMBtu of natural gas per day at a weighted average price of \$2.64 per MMBtu. For the period from April 2016 through December 2017, the Company entered into fixed price swaps for 65,000 MMBtu of natural gas per day at a weighted average price of \$2.64 per MMBtu. Additionally, the Company restructured several existing natural gas swaps and call options. All of the Company's sold call options for 2016 were terminated or moved to 2017. No cash consideration was exchanged as a result of the restructuring transactions. 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.

Amendment to Master Services Agreement

On February 18, 2016, to be effective as of January 1, 2016, the Company amended its Master Services Agreement with Stingray Pressure, dated December 3, 2012. The amendment adjusts the amount of service fees payable for the period from January 1, 2016 through September 30, 2016.

Joint Venture Agreement

In February 2016, the Company entered into a joint venture with Rice Midstream Holdings LLC ("Rice"), a subsidiary of Rice Energy Inc., to develop natural gas gathering assets in eastern Belmont County and Monroe County, Ohio (the "dedicated areas"). The Company owns a 25% interest in the joint venture and Rice acts as

operator and owns the remaining 75% interest in the joint venture. Construction of the gathering assets, which is underway, is expected to provide connectivity of the Company's dry gas gathering systems and interchangeability of natural gas across its firm portfolio.

The joint venture has completed the first phase of the projects: a lateral that connects two existing dry gas gathering systems on which the Company currently flows the majority of its dry gas volumes. The lateral has been commissioned and first flow commenced on February 1, 2016. In addition, the Company and Rice have agreed to negotiate in good faith to expand the joint venture to provide water services to the Company within the dedicated areas. The Company currently anticipates that it will make \$30.0 million to \$35.0 million in cash contributions to the joint venture in 2016.

Revolving Credit Facility

The Company chose to complete its spring borrowing base redetermination under the Company's revolving credit facility ahead of schedule and the bank syndicate affirmed and maintained the existing \$700.0 million borrowing base.

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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	Indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of the Company's 6.625% Senior Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 21, 2015).
4.6	Voting Rights Waiver Agreement, dated June 10, 2015, by and among Gulfport Energy Corporation, Putnam Investment Management, LLC, The Putnam Advisory Company, LLC and Putnam Fiduciary Trust Company (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on June 12, 2015).

Exhibit Number	Description
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+	Amended and Restated Employment Agreement, dated as of April 29, 2015, by and between the Company and Michael G. Moore (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 7, 2015).
10.8+	Employment Agreement, effective as of August 11, 2014, by and between the Company and Aaron Gaydosik (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on March 19, 2015).
10.9+	Employment Agreement, effective as of April 22, 2014, by and between the Company and Ross Kirtley (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on March 19, 2015).
10.10	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).
10.11	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).
10.12	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).
10.13	Third Amendment to Amended and Restated Credit Agreement, dated as of April 10, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 15, 2015).

Exhibit Number	Description
10.14	Fourth Amendment to Amended and Restated Credit Agreement, dated as of May 29, 2015, among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on August 7, 2015).
10.15	Fifth Amendment to Amended and Restated Credit Agreement, dated as of September 18, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on September 24, 2015).
10.16#	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).
10.17#	Amendment to Sand Supply Agreement, dated as of November 3, 2015, by and between Muskie Proppant LLC and Gulfport Energy Corporation (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 5, 2015).
10.18#	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).
10.19*##	Amendment to Amended and Restated Master Services Agreement, dated as of February 18, 2016 to be effective as of January 1, 2016, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC.
10.20+	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).
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.

<u>Exhibit Number</u>	<u>Description</u>
99.1*	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 which portions have been omitted and filed separately with the SEC.

Confidential treatment requested as to certain portions, which portions have been omitted and filed separately with the SEC.



CORPORATE INFORMATION

DIRECTORS

David Houston	Chairman of the Board & Independent Director
Ben T. Morris	Independent Director
Craig Groeschel	Independent Director
Donald Dillingham	Independent Director
C. Doug Johnson	Independent Director
Michael G. Moore	Director
Scott Streller	Independent Director

MANAGEMENT

Michael G. Moore	Chief Executive Officer & President
Aaron Gaydosik	Chief Financial Officer
Keri Crowell	Chief Accounting Officer
Ross Kirtley	Chief Operating Officer
Lester Zitkus	Vice President, Land
Mark Malone	Vice President, Operations
Paul Heerwagen	Vice President, Corporate Development
Randy Wilson	Geologist & Geophysicist
Rob Jones	Vice President, Drilling
Steve Baldwin	Vice President, Reservoir Engineering
Stuart Maier	Vice President, Geosciences
Ty Peck	Managing Director of Midstream Operations



Gulfport is excited to move its Oklahoma City headquarters into a new home during the fall of 2016. After years of operating in separate buildings, we couldn't be more eager to have all Oklahoma City employees under the same roof.

ANNUAL MEETING

The annual meeting of shareholders is scheduled to be held at:

10:00am, Friday, June 10th, 2016

The meeting will be held at the company headquarters at:

14313 North May Avenue, Suite 100
Oklahoma City, OK 73134

TRANSFER AGENT

For information regarding change of address, lost certificates or similar inquiries, please contact our transfer agent:

First Class/Registered/Certified Mail:
Computershare Investor Services
P.O. BOX 30170
College Station, TX 77842-3170

Courier Services:
Computershare Investor Services
221 Quality Circle, Suite 210
College Station, TX 77845

Toll free number for shareholders:
800-884-4225

Outside the U.S. and Canada:
781-575-3120

MARKET INFORMATION

Gulfport Energy's common stock is traded on the NASDAQ Global Select Market under the symbol GPOR.

INVESTOR RELATIONS

For additional information concerning Gulfport Energy's operational and financial results, investors and analysts, please contact Gulfport Investor Relations at 405-242-4888.

MORE INFORMATION

Additional company information, such as company presentations, press releases and other material can be found on the company website at:

www.gulfportenergy.com



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