Table of Contents
Index to Financial Statements

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, 2017
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	**73-1521290**
(State or Other Jurisdiction of Incorporation or Organization)	**(IRS Employer Identification Number)**
3001 Quail Springs Parkway Oklahoma City, Oklahoma	**73134**
(Address of Principal Executive Offices)	**(Zip Code)**

(405) 252-4600
(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, a smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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, 2017, based on the closing price of the common stock on the NASDAQ Global Select Market on June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter ($14.75 per share), was $2,697,110,085.

As of February 12, 2018, 183,105,910 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation's Proxy Statement for the 2017 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
TABLE OF CONTENTS

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, crude oil and natural gas liquids, or NGLs, 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 the SCOOP Woodford and SCOOP Springer plays in Oklahoma. In addition, among other interests, we hold an acreage position along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, an acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly and an approximate 25.1% equity interest in Mammoth Energy Services, Inc., or Mammoth Energy, an oil field services company listed on the Nasdaq Global Select Market (TUSK). We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

As of February 9, 2018, we held leasehold interests in approximately 237,000 gross (213,000 net) acres in the Utica Shale primarily in Eastern Ohio. We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of December 31, 2017, had spud 362 gross wells, 287 of which were completed and were producing. In 2017, we spud 94 gross (88.7 net) wells, of which 32 were completed as producing wells and, as of December 31, 2017, 58 were in various stages of completion and four were still being drilled. We commenced sales from 68 gross (61.1 net) wells in the Utica Shale during 2017. During 2018 (through February 9, 2018), we spud eight gross (6.4 net) wells. As of February 9, 2018, five of these wells were waiting on completion and the other three were still drilling. In addition, other operators drilled 26 gross (8.4 net) wells and commenced sales from 45 gross (9.3 net) wells on our Utica Shale acreage in 2017.

We currently intend to drill 36 to 40 gross (26 to 29 net) horizontal wells, and commence sales from 33 to 37 gross (33 to 37 net) horizontal wells on our Utica Shale acreage in 2018. We currently anticipate seven to eight net horizontal wells will be drilled, and sales commenced from nine to ten net horizontal wells, by other operators on our Utica Shale acreage. We currently expect to spend $425.0 million to $455.0 million on our operated and non-operated activities during 2018.

Aggregate net production from our Utica Shale acreage during the three months ended December 31, 2017 was approximately 95,854 net million cubic feet of natural gas equivalent, or MMcfe, or 1,041.9 MMcfe per day, of which 93% was from natural gas and 7% was from oil and NGLs.

As of February 9, 2018, we held leasehold interests in approximately 50,400 net surface acres in the SCOOP. In 2017, we spud 19 gross (15.7 net) wells, of which seven were completed as producing wells and, as of December 31, 2017, four were being drilled and eight were in various stages of completion. We commenced sales from 13 gross (11.0 net) wells in the SCOOP during 2017. During 2018 (through February 9, 2018), we spud four gross (3.4 net) wells. As of February 9, 2018, one of these wells was waiting on completion and the other three were still drilling. In addition, other operators drilled 31 gross (0.9 net) wells and commenced sales from 23 gross (0.8 net) wells on our SCOOP acreage during the period from February 17, 2017 to December 31, 2017.

We currently intend to drill 15 to 16 gross (10 to 11 net) horizontal wells, and commence sales from 20 to 22 gross (16 to 18 net) horizontal wells on our SCOOP acreage in 2018. We currently anticipate four to five net horizontal wells will be drilled, and sales commenced from two to three net horizontal wells, by other operators on our SCOOP acreage. We currently expect to spend $185.0 million to $210.0 million on our operated and non-operated activities during 2018.

Aggregate net production from our SCOOP acreage during the three months ended December 31, 2017 was approximately 19,008 MMcfe, or an average of 206.6 MMcfe per day, of which 67% was from natural gas and 33% was from oil and NGLs.

In 2017, at our WCBB field, we recompleted 60 gross and net wells and spud ten new wells. In the fourth quarter of 2017, production at WCBB was approximately 1,089 MMcfe, or an average of 11.8 MMcfe per day, of which 99% was from oil and 1% was from natural gas.

In 2017, at our East Hackberry field, we recompleted 20 gross and net wells and spud four new wells. In the fourth quarter of 2017, net production at East Hackberry was approximately 174 MMcfe, or an average of 1.9 MMcfe per day, of which 98% was from oil and 2% was from natural gas.

In 2017, at our West Hackberry field, we recompleted one gross and net well and spud one new well. In the fourth quarter of 2017, net production at West Hackberry was approximately 17 MMcfe, or an average of 188.2 thousand cubic feet of natural gas equivalent, or Mcfe, per day, of which 100% was from oil.

We currently estimate our 2018 activities in our Southern Louisiana fields to be approximately $20.0 million in aggregate to perform recompletion activities.

As of December 31, 2017, we held leasehold interests in approximately 3,383 net acres in the Niobrara Formation in Northwestern Colorado. During the year ended December 31, 2017, there were no wells spud on our Niobrara Formation acreage. In the fourth quarter of 2017, net production from our Niobrara Formation acreage was approximately 26 MMcfe, or an average of 279.8 Mcfe per day, 100% of which was from oil. During 2018, we currently do not anticipate drilling any wells in the Niobrara Formation.

As of December 31, 2017, we held leasehold interests in approximately 778 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 2017, our net production from this acreage was approximately 57 MMcfe, or an average of 622.4 Mcfe per day, of which 81% was from oil, 14% was from natural gas and 5% was from natural gas liquids.

We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. As of December 31, 2017, 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 180,000 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, 2017, we had 5.4 Tcfe of proved reserves with a present value of estimated future net revenues, discounted at 10%, or PV-10, of approximately $2.9 billion and associated standardized measure of discounted future net cash flows of approximately $2.6 billion, excluding reserves attributable to our interests in Grizzly, Tatex II and Tatex III. See Item 2. "*Properties-Proved Oil and Natural Gas Reserves*" for our definition of PV-10 (a non-GAAP financial measure) and a reconciliation of our standardized measure of discounted future net cash flows (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, 2017 reflecting our net interest in our principal producing oil and natural gas properties in the Utica Shale primarily in Eastern Ohio, the SCOOP in Oklahoma, 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)	Productive Wells		Non-Productive Wells		Developed Acreage (2)		Proved Reserves			
								Gas	Oil	NGLs	Total
	Percentages	Gross	Net	Gross	Net	Gross	Net	MMcf	MBbls	MBbls	MMcfe
Utica Shale (3)	42.75/52.07	507	264.05	5	4.23	66,133	55,733	3,766,063	2,597	24,154	3,926,574
SCOOP (4)	30.83/38.52	410	145.85	37	25.72	38,182	38,182	1,058,143	14,048	51,610	1,452,094
West Cote Blanche Bay Field (5)	80.108/100	86	86	162	162	5,668	5,668	605	1,675	—	10,655
E. Hackberry Field (6)	82.33/100	17	17	130	130	2,910	2,910	211	397	—	2,594
W. Hackberry Field	87.5/100	2	2	12	12	726	726	—	149	—	892
Niobrara Formation	34.52/48.61	3	1.46	—	—	1,460	730	127	182	—	1,218
Bakken Formation	1.51/1.83	18	0.3	—	—	386	77	150	107	2	800
Overrides/Royalty Non-operated	Various	662	0.8	—	—	—	—	11	2	—	24
Total		1,705	517.46	346	333.95	115,465	104,026	4,825,310	19,157	75,766	5,394,851

(1) Net Revenue Interest (NRI)/Working Interest (WI) for producing wells.
(2) Developed acres are acres spaced or assigned to productive wells. Approximately 37% of our acreage is developed acreage and has been held by production.
(3) Includes NRI/WI from wells that have been drilled or in which we have elected to participate. Includes 220 gross (32.47 net) wells drilled by other operators on our acreage.
(4) Includes NRI/WI from wells that have been drilled or in which we have elected to participate. Includes 240 gross (8.4 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, 2017, we held leasehold interests in approximately 237,000 gross (213,000 net) acres in the Utica Shale.

Area History

The Ohio Department of Natural Resources reported that in the Utica Shale in Ohio, as of December 31, 2017, there were 1,798 producing horizontal wells, 236 horizontal wells that had been drilled but were not yet completed or connected to a pipeline, 206 horizontal wells that were being drilled and an additional 500 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, 2017, had spud 362 gross wells, 287 of which were completed and were producing. In 2017, we spud 94 gross (88.7 net) wells, of which 32 were completed as producing wells and, as of December 31, 2017, 58 were in various stages of completion and four were still being drilled. We commenced sales from 68 gross (61.1 net) wells in the Utica Shale during 2017. During 2018 (through February 9, 2018), we spud eight gross (6.4 net) wells. As of February 9, 2018, five of these wells were waiting on completion and the other three were still drilling. In addition, other operators drilled 26 gross (8.4 net) wells and commenced sales from 45 gross (9.3 net) wells on our Utica Shale acreage in 2017.

We currently intend to drill 36 to 40 gross (26 to 29 net) horizontal wells, and commence sales from 33 to 37 gross (33 to 37 net) horizontal wells, on our Utica Shale acreage in 2018. We currently anticipate seven to eight net horizontal wells will be drilled, and sales commenced from nine to ten net horizontal wells, by other operators on our Utica Shale acreage during 2018. We currently anticipate our 2018 capital expenditures to be $425.0 million to $455.0 million related to our operated and non-operated Utica Shale activities. As of February 9, 2018, we had three operated horizontal rigs drilling in the play and expect to release one rig in March of 2018 as our contract expires. We plan to run, on average, approximately 2.5 operated horizontal rigs in the Utica Shale in 2018.

Production Status

Aggregate net production from our Utica Shale acreage during the three months ended December 31, 2017 was approximately 95,854 MMcfe, or 1,041.9 MMcfe per day, of which 93% was from natural gas and 7% was from oil and NGLs.

SCOOP (Oklahoma)

Location and Land

As of December 31, 2017, we held leasehold interests in approximately 50,400 gross (50,400 net) surface acres in the SCOOP and approximately 92,900 net reservoir acres, which includes 50,400 net Woodford acres and 42,500 net Springer acres.

Area History

The SCOOP, or South Central Oklahoma Oil Province, is a loosely defined province that encompasses many of the top hydrocarbon producing counties in Oklahoma. The area extends mainly across Grady, Caddo, McClain, Garvin, Stevens, Carter and Love Counties. The region was historically developed by vertical wells drilled through multiple stacked reservoirs ranging from the Cambrian to Permian Periods in age. The play represents the transition to mainly horizontal development targeting predominantly oil and condensate-rich hydrocarbons. The most prolific of these reservoirs include the, Springer (Goddard) Shale, Caney Shale, Woodford Shale and Sycamore Formation.

Geology

The SCOOP play of Oklahoma is located in the southeast portion of the prolific Anadarko Basin. The SCOOP play mainly targets the Devonian to Mississippian aged Woodford Shale. The Woodford Shale is a silica and highly organic rich black shale that was deposited about 320 million to 370 million years ago. Across our position, the Woodford Shale ranges in thickness from 200 to over 400 feet and directly overlies the Hunton Limestone and underlies the Sycamore formation, both of which are also locally productive reservoirs. The Sycamore formation is age equivalent to the Meramec and Osage being developed in the STACK, or Sooner Trend Anadarko Basin Canadian and Kingfisher Counties, play and is located between the organic-rich Woodford and Caney Shales. The Sycamore formation is approximately 250 feet thick across our acreage position, presenting a significant future development target.

Facilities

There are standard land oil and natural gas processing facilities in the SCOOP. 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

On February 17, 2017, we, through our wholly-owned subsidiary Gulfport MidCon, LLC, or Gulfport MidCon (formerly known as SCOOP Acquisition Company, LLC), completed our acquisition, which we refer to as our SCOOP acquisition, of certain assets from Vitruvian II Woodford, LLC, an unrelated third-party seller, for a total purchase price of approximately $1.85 billion, consisting of $1.35 billion in cash, subject to certain adjustments, and approximately 23.9 million shares of the Company's common stock (of which approximately 5.2 million shares were placed in an indemnity escrow). Our SCOOP acquisition included approximately 46,000 net surface acres with multiple producing zones, including the Woodford and Springer formations in the SCOOP resource play, in Grady, Stephens and Garvin Counties, Oklahoma.

Upon our acquisition of these assets, we focused on the high-grading of equipment for our rig fleet to drive efficiencies and lower drill days in the play. Frac design on the wells to date includes an enhanced completion when compared to historical practices for the area. Our 2017 drilling program concentrated on SCOOP Woodford wells, however, during 2017, we also spud and turned-to-sales our first Springer and Sycamore wells.

In 2017, we spud 19 gross (15.7 net) wells, of which seven were completed as producing wells and, as of December 31, 2017, eight were in various stages of completion and four were still being drilled. We commenced sales from 13 gross (11.0 net) wells in the SCOOP during 2017. During 2018 (through February 9, 2018), we spud four gross (3.4 net) wells. As of February 9, 2018, one of these wells was waiting on completion and the other three were still drilling. In addition, other operators drilled 31 gross (0.9 net) wells and commenced sales from 23 gross (0.8 net) wells on our SCOOP acreage in 2017.

We currently intend to drill 15 to 16 gross (10 to 11 net) horizontal wells, and commence sales from 20 to 22 gross (16 to 18 net) horizontal wells, on our SCOOP acreage in 2018. We currently anticipate four to five net horizontal wells will be drilled, and sales commenced from two to three net horizontal wells, by other operators on our SCOOP acreage during 2018. We currently anticipate our 2018 capital expenditures to be $185.0 million to $210.0 million related to our operated and non-operated SCOOP activities. As of February 9, 2018, we had four operated horizontal rigs drilling in the play and expect to release two rigs in mid-summer 2018 as our contracts expire. We intend to run, on average, three operated horizontal rigs in the SCOOP during 2018.

Production Status

Aggregate net production from our SCOOP acreage during the three months ended December 31, 2017 was approximately 19,008 net MMcfe, or 206.6 MMcfe per day, of which 67% was from natural gas and 33% was from oil and natural gas liquids.

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 1,093 wells drilled as of December 31, 2017, 980 were completed as producing wells. From the date of our acquisition of WCBB in 1997 through December 31, 2017, we drilled 273 new wells, 240 of which were productive, for an 88% success rate. As of December 31, 2017, estimated field cumulative gross production was 200 MMBO and 237.8 Bcf of gas. Of the 1,093 wells drilled in WCBB as of December 31, 2017, 86 were producing, 162 were shut-in, and six were being used as salt water disposal wells. The other 839 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 1,093 wells that had been drilled in the field as of December 31, 2017, 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 2017, at our WCBB field, we recompleted 60 gross and net wells and spud eight new wells. As of February 9, 2018, we had recompleted seven gross and net wells during 2018 in our WCBB field.

Production Status

In the fourth quarter of 2017, our net production at WCBB was approximately 1,089 MMcfe, or an average of 11.8 MMcfe per day, of which 99% was from oil and 1% was from natural gas.

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 82.33% average NRI) in certain producing oil and natural gas properties situated in the East Hackberry field. As of December 31, 2017, 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.

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 2017 was over 4,758 MBO and 332 Bcf of casinghead gas production. A total of 272 wells have been drilled on our portion of the field. As of December 31, 2017, 17 wells had daily production, 130 were shut-in and three had been converted to salt water disposal wells. The remaining 122 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, two natural gas compressors, dehydration units and salt water disposal systems.

Recent Activity

During 2017 at East Hackberry, we recompleted 20 gross and net wells and spud four new wells. As of February 9, 2018, we had recompleted two gross and net wells during 2018 in our East Hackberry field.

Production Status

In the fourth quarter of 2017, our net production at East Hackberry was approximately 174 MMcfe, or an average of 1.9 MMcfe per day, of which 98% was from oil and 2% was from natural gas.

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 87.50% NRI) in 1,032 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 2017 was 493 MBO and 140 Bcf of natural gas. As of December 31, 2017, 42 wells had been drilled on our portion of West Hackberry.

As of December 31, 2017, two of such wells were producing, 12 were shut-in and one was being used as a salt water 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 2017 at West Hackberry, we recompleted one gross and net well and spud one new well. As of February 9, 2018, we had recompleted one gross and net well during 2018 in our West Hackberry field.

Production Status

In the fourth quarter of 2017, our net production at West Hackberry was approximately 17 MMcfe, or an average of 188.2 Mcfe per day, of which 100% was from oil.

Facilities

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

During 2018, we intend to run one recompletion rig in our Southern Louisiana fields.

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, 2017, we held leases for approximately 3,383 net acres. In 2017, 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 2017, net production from our Niobrara Formation acreage was approximately 26 MMcfe, or an average of 279.8 Mcfe per day, 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 2017. We do not anticipate drilling any wells in the Niobrara Formation during 2018.

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, 2017, we held approximately 778 net acres, interests in 18 wells and overriding royalty interests in certain existing and future wells.

Production Status

In the fourth quarter of 2017, our net production from this acreage was approximately 57 MMcfe, or an average of 622.4 Mcfe per day, of which 81% was from oil, 14% was from natural gas and 5% was from natural gas liquids.

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 2017. We do not anticipate drilling any wells in the Bakken Formation during 2018.

Additional Properties

In addition to our core properties discussed above, 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, 2017:

Field	State	Parish/County	Acreage Working Interest	Overriding Royalty Interests	Producing Wells	Non-Producing Wells
Deer Island	Louisiana	Terrebonne	3.125%	—	1	—
Napoleonville	Louisiana	Assumption	—	2.5%	3	—
Crest	Texas	Ochiltree	2%	—	1	—
Eagle City South	Oklahoma	Dewey	1.04%	—	1	—
Fay South	Oklahoma	Blaine	0.301%	—	1	—
Squaw Cheek	Oklahoma	Blaine	0.13%	—	1	—
Watonga Chickasha Trend	Oklahoma	Canadian	0.052%	—	1	—
Green River Basin	Colorado	Moffat	0.0686%	—	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, 2017, 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 high-graded three oil sands projects to 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 regulatory approval for up to 11,300 barrels per day of bitumen production. Algar Lake production peaked at 2,200 barrels per day during the ramp-up phase of the SAGD facility, however, in April 2015, Grizzly made the decision to suspend operations at its Algar Lake facility due to the commodity price drop and its effect on project economics. Grizzly continues to monitor market conditions as it assesses startup plans for the facility. Grizzly also owns the May River property comprising approximately 47,000 acres. An initial 12,000 barrel per day development application covering the eastern portion of the May River lease has been deemed complete from the Alberta Energy Regulator and is awaiting final approval, which is expected in early 2018. A 2-D seismic program covering approximately 83 kilometers has been completed to more fully define the resource over the remaining lease beyond the development application area. In 2017, Grizzly advanced plans for cold heavy oil sands production, or CHOPS, at its Cadotte property in Peace River. However, plans for development are dependent on stabilized commodity prices. Grizzly continues to advance rail marketing strategies to ensure consistent and flexible access to premium markets for its future production. Grizzly is also advancing a project to utilize its Windell truck to rail terminal located near Conklin, Alberta, for movement of liquefied petroleum gas, or LPG, into the oil sands area for use in Thermal applications by SAGD producers.

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 180,000 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 MMcf per day. For 2017, net gas production was approximately 78 MMcf per day and condensate production was 250 barrels per day. PTT Exploration and Production Public Company Limited operates the field with a 55% interest. Other interest owners include APICO (35% 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.

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 2012, we participated in the formation of Stingray Pressure Pumping LLC, or Stingray Pressure, 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 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 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. On October 19, 2016, Mammoth Energy Services, Inc., or Mammoth Energy, which is the parent company of Mammoth, completed its initial public offering, or the IPO, of 7,750,000 shares of its common stock at a public offering price of $15.00 per share, of which 7,500,000 shares were sold by Mammoth Energy and 250,000 shares were sold by certain selling stockholders, including 76,250 shares sold by us for which we received net proceeds of $1.1 million. Prior to the completion of the IPO, we were issued 9,150,000 shares of Mammoth Energy common stock in return for the contribution of our 30.5% interest in Mammoth Energy Partners LLC (as the successor to Mammoth). Immediately following the completion of the IPO, we owned an approximate 24.2% interest in Mammoth Energy. We used the net proceeds for the sale of our Mammoth Energy shares in the IPO for general corporate purposes.

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 Cementing LLC, or Stingray Cementing, with an initial ownership of 50%. Stingray Cementing provides well completion and other well services. In 2014, we acquired a 25% equity interest in Sturgeon Acquisitions LLC, or Sturgeon. Sturgeon owns an entity that operates sand mines that produce hydraulic fracturing grade sand. On June 5, 2017, we acquired approximately 2.0 million shares of Mammoth Energy common stock in connection with our contribution of all of our membership interests in Sturgeon, Stingray Energy and Stingray Cementing, bringing our equity interest in Mammoth Energy to approximately 25.1%.

In February 2016, we, through our wholly owned subsidiary Gulfport Midstream Holdings, LLC, or Midstream Holdings, entered into an agreement 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, through a new entity, Strike Force Midstream LLC, or Strike Force. In 2017, Rice was acquired by EQT Corporation, or EQT. We own a 25% interest in Strike Force. EQT now acts as operator and owns the remaining 75% interest in Strike Force. Construction of the gathering assets, which is ongoing, provides gathering services for wells operated by Gulfport and other operators and connectivity of existing dry gas gathering systems. First flow for Strike Force commenced on February 1, 2016.

See Note 4 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation. In addition, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Marketing and Customers

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the demand for oil and natural gas and the level of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of gas sold in interstate commerce. Both our Utica Shale and SCOOP natural gas production is sold to various counterparties through established NAESBs at the plant tailgates and various central delivery points owned and operated by third party midstream companies. Our natural gas production is sold under monthly, seasonal and long-term contracts and, as needed, through daily transactions. When sold in basin, pricing is typically based on Platts Gas Daily - Texas Eastern M2 Zone for our Utica Shale acreage and Platts Gas Daily - Panhandle Tx-Ok and NGPL Midcontinent for our SCOOP acreage. To maintain flow assurance and price stability, and as discussed under "*–Transportation and Takeaway Capacity*," we have entered into agreements in both the Utica and SCOOP basins to transport a portion of our natural gas production to various delivery points. These agreements allow us to price the molecules at those various downstream markets less transportation charges. The majority of our Utica oil is sold to purchasers at the tailgate of a condensate stabilizer located near Cadiz, Ohio, owned and operated by MPLX Energy Logistics, or MPLX. Our SCOOP oil is sold at the lease to various purchasers at respective area postings. In Southern Louisiana, our oil is sold to parties taking custody at the lease or at the outlet from a Gulfport oil storage barge. Our NGLs in the Utica Shale are primarily fractionated at MPLX's Hopedale facility. The majority of the product is marketed by the operator with Gulfport receiving the benefit from the MPLX's aggregation and established logistic network. Our SCOOP NGLs are primarily sent to Mont Belvieu on our commitment to DCP Souther Hills and purchased at the fractionation facility. For the year ended December 31, 2017, sales to BP Energy Company, or BP, accounted for approximately 40% of our total oil, natural gas and NGL revenues, before the effects of hedging.

As of December 31, 2017, we had an average of approximately 560,800 MMBtu per day of firm sales contracted with third parties for 2018. We had an average of approximately 659,000 MMBtu per day, 526,000 MMBtu per day, 372,000 MMBtu per day, 272,000 MMBtu per day and 240,000 MMBtu per day contracted with third parties for 2019, 2020, 2021, 2022 and thereafter, respectively.

Transportation and Takeaway Capacity

In Ohio and Oklahoma, as of December 31, 2017, we had entered into firm transportation contracts to deliver approximately 1,095,000 MMBtu to 1,245,000 MMBtu per day for 2018. For 2019 and 2020, we had entered into firm transportation contracts to deliver approximately 1,205,000 MMBtu to 1,405,000 MMBtu per day. We continuously monitor the need to secure additional firm transportation contracts for incremental volumes from our Utica Shale and SCOOP acreage but expect additional long term contracts to be limited in 2018. 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, which went into partial service in December 2016 and full service in January 2017, 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 which began in 2016 allowing additional access to Gulf Coast delivery points;
- 54,000 MMBtu per day of firm capacity on Texas Gas Transmission facilities which began in 2017 allowing additional access to Gulf Coast delivery points;
- 100,000 MMBtu per day of firm capacity on Texas Eastern Transmission facilities which began in 2017 allowing additional access to Midwest delivery points;
- 150,000 MMBtu per day of firm capacity on Energy Transfer’s Rover Pipeline facilities, 50,000 of which began in 2017 allowing additional access to Midwest delivery points, and 100,000 expected to begin in 2018 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 which began in late 2017 allowing additional access to Gulf Coast delivery points; and
- 50,000 MMBtu per day of firm capacity on Enable Oklahoma Intrastate which was acquired in early 2017 through our SCOOP acquisition allowing additional connectivity to East Texas and Gulf Coast markets; and
- 30,000 MMBtu per day of firm capacity on Enable Gas Transmission facilities which was acquired in early 2017 through our SCOOP acquisition allowing additional access to East Texas delivery points; and
- 20,000 MMBtu per day of firm capacity on Midcontinent Express Pipeline facilities which began mid 2017 allowing additional access to Gulf Coast delivery points; and
- 50,000 MMBtu per day of firm capacity on Gulf Crossing Pipeline facilities which began mid 2017 allowing additional access to Gulf Coast delivery points; and
- 200,000 MMBtu per day of firm capacity on Cheniere Midship Pipeline facilities which will begin in 2019 allowing additional access to East Texas 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 and Oklahoma positions.

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, the SCOOP Woodford and SCOOP Springer plays in Oklahoma, 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 related to our owned or operated facilities. Liability under such laws and regulations is often 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 non-hazardous waste requirements. 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.” Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. 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 impose 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. 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. 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 a permit issued by the U.S. Army Corps of Engineers, or the Corps. On June 29, 2015, the EPA and the Corps jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. To the extent the rule expands the range of properties subject to the Clean Water Act’s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Following its promulgation, numerous states and industry groups challenged the rule and, on October 9, 2015, a federal court stayed the rule’s implementation nationwide, pending further action in court. In response to this decision, the EPA and the Corps have resumed nationwide use of the agencies’ prior regulations defining the term “waters of the United States.” Further, on February 28, 2017, President Trump signed an executive order directing the relevant executive agencies to review the rules and to initiate rulemaking to rescind or revise them, as appropriate under the stated policies of protecting navigable waters from pollution while promoting economic growth, reducing uncertainty and showing due regard for Congress and the states. On July 27, 2017, the EPA and the Corps published a proposed rule to rescind the 2015 rules and, on November 22, 2017, the agencies published a proposed rule to maintain the status quo pending the agencies review of the 2015 rules.

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 June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants, 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*." Also, on May 12, 2016, the EPA issued a final rule regarding the criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. 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. In May 2010, the EPA adopted regulations establishing 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 August 26, 2016, the EPA proposed changes needed to bring EPA's air permitting regulations in line with the Supreme Court's decision on GHG permitting. The proposed rule was published in the Federal Register on October 3, 2016 and the public comment period closed on December 2, 2016.

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.

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 participated in 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 went into effect on November 4, 2016. The Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of and value of our products and reserves. As our operations also emit greenhouse gases directly, current and future laws or regulations limiting such emissions could increase our own costs. 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.

There have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, 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 or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While we are not a party to any such 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 hotter or 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, or the ESA and analogous state statutes, 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 restricts activities that may adversely affect listed species or their habitat. 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 and SCOOP 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. However, legislation has been proposed in recent sessions of Congress to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process.

Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as “Class II” UIC wells.

In addition, the EPA previously announced plans to develop a Notice of Proposed Rulemaking by June 2018, 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 June 28, 2016, EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. 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. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation’s energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

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. On June 21, 2016, the United States District Court for Wyoming set aside the rule, holding that the BLM lacked Congressional authority to promulgate the rule. The BLM has appealed the decision to the Tenth Circuit Court of Appeals. Also, on November 15, 2016, the BLM finalized a rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The rule requires 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 also clarifies when operators owe the government royalties for flared gas. State and industry groups have challenged this rule in federal court, asserting that the BLM lacks authority to prescribe air quality regulations. On March 28, 2017, President Trump signed an executive order directing the BLM to review the above rules and, if appropriate, to initiate a rulemaking to rescind or revise them. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule. Also, on December 8, 2017, the BLM published a final rule to suspend or delay certain requirements of the 2016 methane rule until January 17, 2019. Further legal challenges are expected. At this time, it is uncertain when, or if, the rules will be implemented, and what impact they would have on our operations.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. 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. If new or more stringent state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

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 of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, natural gas 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 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 ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the plugging and abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. 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 standard, common carriers must offer service to all similarly situated 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 horizontal well pads. Under these new rules, operators must submit detailed horizontal well pad design packages prepared by a professional engineer for review and certification by the ODNR Division of Oil and Gas Resources Management prior to the commencement of any oil and natural gas activity. These rules resulted in increased construction costs for operators. Furthermore, pursuant to new rules approved in August 2016, operators must immediately notify ODNR regarding certain oil and natural gas releases.

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, cyber and employers' liability and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery. Additionally, our insurance is subject to exclusions 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 $25.0 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. 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 and SCOOP 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 2017 and 2016 were approximately $0.2 million and $0.1 million. 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, Oklahoma and Louisiana, we also actively manage an incident response planning program and coordinate with applicable state agency personnel on spills and releases through the Ohio, Oklahoma and Louisiana Incident Notification Hotlines. We also participate in the Ohio, Oklahoma and Louisiana Emergency Planning and Community Right to Know Act (EPCRA) programs, 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 approximately 120,000 square feet of office space in Oklahoma City, Oklahoma that serves as our corporate headquarters. We also own an approximately 28,500 square foot office building in Oklahoma City, Oklahoma where some of our employees office.

We own an approximately 12,300 square feet building located in St. Clairsville, Ohio that serves as our headquarters for our Ohio operations. 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 lease approximately 3,700 square feet in a building in Lafayette that we use as our Louisiana headquarters. We also lease an office in Lindsay, Oklahoma that serves as our Oklahoma production field office. Each of these properties is suitable and adequate for its use.

Employees

At December 31, 2017, we had 331 employees.

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 volatility in prices for oil and natural gas, have in the past adversely affected, and may continue in the future 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 2016, West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, prices ranged from $26.19 to $54.01 per barrel and the Henry Hub spot market price of natural gas ranged from $1.49 to $3.80 per MMBtu. During 2017, WTI prices ranged from $42.48 to $60.46 per barrel and the Henry Hub spot market price of natural gas ranged from $2.44 to $3.71 per MMBtu. If the prices of oil and natural gas decline, 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 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 2018 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 2018 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 2018 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 midstream agreement 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 economic volatility 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 in the past precipitated, and may in the future precipitate, an economic slowdown. Concerns about global economic growth could have a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

Our development, 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 2018 to be in the range of $630.0 million to $685.0 million and an additional $140.0 million to $150.0 million for leasehold expenditures, primarily lease extensions in the Utica Shale, and for cash capital contributions to our midstream joint venture with EQT 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 2018 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.

Recent decisions by the Ohio Supreme Court interpreting the Ohio Dormant Mineral Act relating to preservation of mineral rights by surface owners could require certain curative efforts to vest title in a portion of our leasehold acreage, increase our leasehold expenses, subject us to payment of additional royalties and/or result in the loss of some of our leasehold acreage in Ohio.

On September 15, 2016, the Ohio Supreme Court issued a series of decisions relating to the Ohio Dormant Mineral Act, which we refer to as the ODMA. In the lead case, Corban v. Chesapeake Exploration L.L.C., the court concluded that the 1989 version of the ODMA did not transfer ownership of dormant mineral rights automatically, by operation of law. Instead, prior to 2006, surface owners were required to bring a quiet title action in order to establish abandonment of mineral rights. After June 30, 2006, (the effective date of the 2006 version of the ODMA), surface owners are required to follow the statutory notice and recording procedures enacted in 2006. We have assessed the impact of these recent Ohio Supreme Court decisions on our operations in Ohio where the majority of our acreage and our producing properties are located and have taken steps to mitigate any potential risks identified as a result of our assessment. However, the Ohio Supreme Court decisions could require certain curative efforts to vest title in a portion of our leasehold acreage, increase our leasehold expense, subject us to payment of additional royalties and/or result in the loss of some of our leasehold acreage in Ohio, any of which could have an adverse effect on our results of operations and financial condition.

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, 2017, 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 high-graded three oil sands projects to various stages of development. Grizzly commenced commercial production from its Algar Lake Phase 1 SAGD oil sand project during the second quarter of 2014 and has regulatory approval for up to 11,300 barrels per day of bitumen production. Algar Lake production peaked at 2,200 barrels per day during the ramp-up phase of the SAGD facility, however, in April 2015, Grizzly made the decision to suspend operations at its Algar Lake facility due to the commodity price drop and its effect on project economics. Grizzly continues to monitor market conditions as it assesses startup plans for the facility. We reviewed our investment in Grizzly as of September 30, 2015 and December 31, 2015, and again at March 31, 2016, for impairment, resulting in an aggregate other than temporary impairment write down of $101.6 million for the year ended December 31, 2015 and $23.1 million for the year ended December 31, 2016. As of and during the period ended December 31, 2017, commodity prices had increased as compared to the quarter ended March 31, 2016, and there were no impairment indicators that required further evaluation for impairment. If commodity prices 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 certain 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 and our WCBB and Hackberry fields at December 31, 2017, 2016 and 2015, our SCOOP acreage at December 31, 2017 and our Niobrara field at December 31, 2015 and (ii) our personnel with respect to our overriding royalty and non-operated interests at December 31, 2017, 2016 and 2015 and our Niobrara field at December 31, 2017 and 2016. 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 2017, 2016 and 2015 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, 2017, 2016 and 2015, 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 2017, 2016 and 2015 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, 2017, 2016 and 2015, respectively, in accordance with the revised guidelines of the SEC applicable to reserves estimates for such years.

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 64.9% of our total estimated proved reserves at December 31, 2017, 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 a portion of our exploration and development activity, historically there has been no or only limited infrastructure in this area and the commencement of production from our initial and subsequent wells on our Utica Shale acreage has been delayed due to challenges in obtaining rights-of-way and acquiring necessary state and federal permitting and the completion of facilities by our midstream service provider.

If production from our Utica Shale or SCOOP 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, 2017, we had entered into firm transportation contracts to deliver approximately 1,095,000 MMBtu to 1,245,000 MMBtu per day for 2018 and approximately 1,205,000 MMBtu to 1,405,000 MMBtu per day for 2019 through 2020. 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 or SCOOP 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, Oklahoma and Louisiana, making us vulnerable to risks associated with operating in these regions.

Our largest fields by production are located in Eastern Ohio, Oklahoma 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, Oklahoma and Louisiana 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 and restrictions on our activities as a result of 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 (which could cause us to cease operations), 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 tended to increase over time. 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.

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 SCOOP play in Oklahoma. 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 SCOOP play in Oklahoma. On February 17, 2017, we completed our SCOOP acquisition, which included approximately 46,000 net surface acres with multiple producing zones, including the Woodford and Springer formations in the SCOOP resource play, in Grady, Stephens and Garvin Counties, Oklahoma. The area was historically developed by vertical wells drilled through multiple stacked reservoirs; however, the current play represents the transition to mainly horizontal development. 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 limited production history from horizontal wells in the SCOOP exists 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 SCOOP may decline if drilling results are unsuccessful. We cannot assure you that unproved property acquired, or undeveloped acreage leased, by us in the SCOOP 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 (including the SCOOP) 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 exploration 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 22% of our total Utica Shale undeveloped acreage will be subject to expiration in 2018, with 8% of such acreage expiring in 2019, 9% in 2020 and 17% 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, 2017, leases representing 6%, 67% and 5% respectively, of our total SCOOP undeveloped acreage are schedule to expire in 2018, 2019 and 2020. As of December 31, 2017, leases representing 11% and 53%, respectively, of our total Niobrara Formation undeveloped acreage are scheduled to expire in 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 impose increasingly strict requirements for water and air pollution control and solid waste management, which trend may continue. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. 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. We use hydraulic fracturing extensively in connection with the development and production of certain of our oil and natural gas properties. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process.

In addition, 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.

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 reduce the volumes of oil and natural gas that we can recover economically and cause us to incur substantial compliance costs. Reduced production and/or 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.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states, including in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells.

We dispose of large volumes of produced water gathered from our drilling and production operations in our Louisiana fields by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of produced water gathered from our drilling and production activities by own disposal wells, could have a material adverse effect on our business, financial condition and results of operations. We do not currently inject produced water in our Utica or SCOOP operations.

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 species or their habitat. 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 threatened or 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.

Regulation of greenhouse emissions 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*."

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, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, 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 or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While our business is not a party to any such 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 hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938, or the NGA, exempts natural gas gathering facilities from regulation by FERC. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish whether a pipeline performs a gathering function and therefore is exempt from FERC's jurisdiction under the NGA. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is a fact-based determination. The classification of facilities as unregulated gathering is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress, which could cause our revenues to decline and operating expenses to increase and may materially adversely affect our business, financial condition or results of operations. 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 the purchasers of our production could adversely affect our business, results of operations, financial condition and cash flows.

The largest purchaser of our oil and natural gas during the year ended December 31, 2017 accounted for approximately 40% of our total oil, natural gas and NGL revenues. If this purchaser, or one or more other significant purchasers, are 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 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 2017, 2016 and 2015 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 $715.5 million for the year ended December 31, 2016. 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.

Recently enacted U.S. tax legislation as well as future U.S. and state tax legislations may adversely affect our business, results of operations, financial condition and cash flow.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act, or the Tax Act, that significantly reforms the Internal Revenue Code of 1986, as amended, or the Code. Among other changes, the Tax Act (i) permanently reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) eliminates the deduction for certain domestic production activities, (iv) imposes new limitations on the utilization of net operating losses, and (v) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense. The Tax Act is complex and far-reaching, and we cannot predict with certainty the resulting impact its enactment will have on us. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued, and any such changes in our interpretations and assumptions could have an adverse effect on our business, results of operations, financial condition and cash flow.

In addition, from time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws affecting the oil and gas industry. For example, legislations have been introduced in the past to (i) eliminate the immediate deduction for intangible drilling and development costs, (ii) repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) extend the amortization period for certain geological and geophysical expenditures. While these specific changes are not included in the Tax Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. These proposed changes in the U.S. tax law, if adopted, or other similar changes that would impose additional tax on our activities or reduce or eliminate deductions currently available with respect to natural gas and oil exploration, development or similar activities, could adversely affect our business, results of operations, financial condition and cash flows.

Additional state taxes on natural gas extraction may be imposed as a result of future legislation.

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. The Ohio State Senate held a hearing on the bill, but there was no further movement before the recess of that General Assembly.

In February 2015, the Governor of Ohio proposed another plan to the new General Assembly to enact new severance taxes on the oil and gas industry. This proposal was part of a 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. This severance tax increase was removed from the Bill that was ultimately passed by the Ohio House.

A new General Assembly took office in January 2017, and the Governor of Ohio proposed a new severance tax initiative. The proposal would impose a fixed rate of 6.5% for crude oil and natural gas when sold at the wellhead and a lower rate of 4.5% at later stages of distribution for natural gas and natural gas liquids. The proposal was again met with opposition and was not included in the final budget that was passed and signed by the Governor on June 30, 2017 and effective for the period of July 1, 2017 through June 30, 2019.

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.

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 2018 production, we may still be adversely affected by continuing and prolonged declines in the price of natural gas and oil.

We use derivative instruments 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 derivative instruments, 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.

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.

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, 2017, we had total indebtedness (net of unamortized debt issuance costs) of approximately $2.0 billion, primarily attributable to our senior notes. We had borrowing base availability of $759.0 million under our secured revolving credit facility after giving effect to an aggregate of $241.0 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 indentures;

- 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 our 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 our 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 indentures governing our 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 indentures governing our senior notes and in future debt instruments may restrict our ability to pursue our business strategies.

Our secured revolving credit facility and the indentures governing our 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 indentures governing our 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 indentures governing our 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 our 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 $1.2 billion, with an elected commitment of $1.0 billion. 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, 2017, 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 indentures governing our senior notes restrict, but in each case do not completely prohibit, us from doing so. As of December 31, 2017, our borrowing base under our revolving credit facility was set at $1.2 billion, with an elected commitment of $1.0 billion, and we had no borrowings outstanding under this facility. In addition, the indentures governing our senior notes allow us to issue additional notes under certain circumstances which will also be guaranteed by the guarantors. The indentures governing our senior notes also allow us to incur certain other additional secured debt and allow us to have subsidiaries that do not guarantee the senior notes and which may incur additional debt, which would be structurally senior to our senior notes. In addition, the indentures governing our senior notes do 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 our 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 our 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, 2017, 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, 2017, 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.

There is no guarantee that we will repurchase shares of our common stock under our recently announced stock repurchase program at a level anticipated by our stockholders, which could reduce returns to our stockholders. Decisions to repurchase our common stock will be at the discretion of our board of directors based upon a review of relevant considerations.

In January 2018, our board of directors approved a stock repurchase program to acquire up to $100.0 million of our outstanding common stock during 2018. The repurchase program does not require us to acquire any specific number of shares and, as of February 22, 2018, we have not repurchased any shares of our common stock under our stock repurchase program or otherwise. Our board of director’s determination to repurchase shares of our common stock will depend upon market conditions, applicable legal requirements, contractual obligations and other factors that the board of directors deems relevant. Based on an evaluation of these factors, our board of directors may determine not to repurchase shares or to repurchase shares at reduced levels from those anticipated by our stockholders, any or all of which could reduce returns to our stockholders.

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

As of December 31, 2017, we had a net operating loss, or NOL, carry forward of approximately $574.4 million for federal income tax purposes. If we were to experience an “ownership change,” as determined under Section 382 of the Code, our ability to offset taxable income arising after the ownership change with NOLs generated prior to the ownership change would be limited, possibly substantially. In general, an ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more “5% shareholders” (as defined in the Internal Revenue Code) at any time during a rolling three-year period.

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 12, 2018, there were 183,105,910 shares of our common stock issued and outstanding, excluding 976,027 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, 2017 were prepared by NSAI with respect to our assets in the Utica Shale in Eastern Ohio (73% of our proved reserves at December 31, 2017), the SCOOP Woodford and SCOOP Springer plays in Oklahoma which we acquired on February 17, 2017 (27% of our proved reserves at December 31, 2017) and our WCBB and Hackberry fields (less than 1% of our proved reserves at December 31, 2017). Reserve estimates at December 31, 2016 were prepared by NSAI with respect to our assets in the Utica Shale in Eastern Ohio and our WCBB and Hackberry fields. Reserve estimates at December 31, 2015 were prepared by NSAI with respect to our assets in the Utica Shale in Eastern Ohio and our WCBB, Hackberry and Niobrara fields. Our personnel prepared reserve estimates with respect to our Niobrara field as well as our overriding royalty and non-operated interests (less than 1% of our proved reserves) at December 31, 2017 and 2016. At December 31, 2015, our personnel prepared reserve estimates with respect to our overriding royalty and non-operated interests (less than 1% of our proved reserves).

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.

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, SCOOP, WCBB and Hackberry 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. In addition, our geophysical staff has over 100 years combined industry experience and our reservoir staff has approximately 50 years combined 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;
- annual review by our senior management of adjustments to our previously adopted development plan and considerations involved in making such adjustments; and
- annual 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, 2017, 2016 and 2015:

	Year Ended December 31,								
	2017			2016			2015		
	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	10,245	1,616,930	36,247	4,882	744,797	14,299	6,120	652,961	12,910
Proved undeveloped	8,912	3,208,380	39,519	664	1,422,271	5,828	338	907,184	4,826
Total (1)	19,157	4,825,310	75,766	5,546	2,167,068	20,127	6,458	1,560,145	17,736

	Year Ended December 31,		
	2017	2016	2015
Total net proved oil and natural gas reserves (MMcfe) (1)	5,394,851	2,321,108	1,705,312
PV-10 value (in millions) (2)	$ 2,883.0	$ 696.0	$ 765.8
Standardized measure (in millions) (3)	$ 2,643.6	$ 688.0	$ 764.3

(1) Estimates of reserves as of year-end 2017, 2016 and 2015 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, 2017, 2016 and 2015, respectively, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2017, 2016 and 2015. 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, 2017, 2016 and 2015 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 $51.34 per barrel and $2.98 per MMBtu for 2017, $42.75 per barrel and $2.48 per MMBtu for 2016 and $50.28 per barrel and $2.59 per MMBtu for 2015, 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,		
	2017	2016	2015
	(In thousands)		
Standardized measure of discounted future net cash flows	$ 2,643,564	$ 688,040	$ 764,331
Add: Present value of future income tax discounted at 10%	239,468	7,927	1,432
PV-10 value	$ 2,883,032	$ 695,967	$ 765,763

(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 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, 2017 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 2017 of $51.34 per barrel and $2.98 per MMBtu. Holding production and development costs constant, if our 2017 reserves were calculated using the December 31, 2017 price of $60.42 per barrel and $2.95 per MMBtu, our discounted future net cash flows before income taxes would have been approximately $3.0 billion, or $0.1 billion more than our actual PV-10 value of $2.9 billion at December 31, 2017.

The table below provides the 2017 SEC pricing of benchmark prices as well as the unweighted average of the months ended December 31, 2017 and January 31, 2018:

	SEC Pricing 2017	2-month Average 2018
Henry Hub Natural Gas (per MMBtu)	$ 2.98	$ 2.91
WTI Crude Oil (per Bbl)	$ 51.34	$ 60.81

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.

Changes in Proved Reserves during 2017.

The following table summarizes the changes in our estimated proved reserves during 2017 (in Bcfe):

Proved Reserves, December 31, 2016	**2,321**
Purchases of oil and natural gas reserves in place	1,511
Extensions and discoveries	1,629
Revisions of prior reserve estimates	332
Current production	(398)
Proved Reserves, December 31, 2017	**5,395**

Purchases of oil and natural gas reserves in place. These are additions to proved reserves resulting from the purchases of minerals in place during a period. During 2017, we purchased 1.5 Tcfe of proved oil and natural gas reserves through our SCOOP acquisition.

Extensions and discoveries. These are additions to our proved reserves that result from (i) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (ii) discovery of new fields with proved reserves or of new reservoirs of proved reserves in existing fields. Extensions and discoveries of 1.6 Tcfe of proved reserves were attributable to the continued development of our Utica Shale acreage.

Revisions of prior reserve estimates. Revisions represent changes in previous reserve estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

Commodity prices increased significantly in 2017. The 12-month average price for natural gas increased from $2.48 per MMBtu for 2016 to $2.98 per MMBtu for 2017, the 12-month average price for NGLs increased from $9.91 per barrel for 2016 to $18.40 per barrel for 2017, and the 12-month average price for crude oil increased from $42.75 per barrel for 2016 to $51.34 per barrel for 2017. We experienced positive revisions of 201.3 Bcfe in estimated proved reserves in 2017 due to an increase in well performance, 214.1 Bcfe due to an increase in pricing and 95.9 Bcfe due to changes in our ownership interests. These positive revisions were partially offset by downward revisions of 133.0 Bcfe in estimated proved reserves due to a decline in well performance specific to one area in our Utica field and a decline of 45.7 Bcfe in estimated proved reserves in 2017 primarily due to the exclusion of ten PUD locations in our Utica field, five of which we operate and five of which are operated by others operators, that were excluded due to changes in drilling schedules. An additional downward revision of 0.6 Bcfe was due to two PUD locations in our Southern Louisiana fields that had not been drilled within five years of initial booking.

Additional information regarding estimates of proved reserves, proved developed reserves and proved undeveloped reserves at December 31, 2017, 2016 and 2015 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.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2017, our proved undeveloped reserves totaled 8,912 MBbls of oil, 3,208,380 MMcf of natural gas and 39,519 MBbls of NGLs, for a total of 3,498,965 MMcfe. Approximately 73% and 27% of our PUDs at year-end 2017 were located in our Utica field and our SCOOP field, respectively. PUDs will be converted from undeveloped to developed as the applicable wells commence production or there are no material incremental completion capital expenditures associated with such proved developed reserves.

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 2017, we did not deviate from our development plan with respect to our PUD locations booked in our reserve report for the year ended December 31, 2016 and scheduled to be drilled during 2017, other than to drill 14 additional PUD locations than initially scheduled to be drilled during 2017.

The following table summarizes the changes in our estimated proved undeveloped reserves during 2017 (in Bcfe):

Proved Undeveloped Reserves, December 31, 2016	**1,461**
Purchases of oil and natural gas reserves in place	947
Extensions and discoveries	1,467
Conversion to proved developed reserves	(486)
Revisions of prior reserve estimates	110
Proved Undeveloped Reserves, December 31, 2017	**3,499**

Purchases of oil and natural gas reserves in place. During 2017, we purchased 946.7 Bcfe of proved undeveloped oil and natural gas reserves through our SCOOP acquisition.

Extensions and discoveries. Our additions of 1.5 Tcfe were primarily attributable to 2017 extensions in our Utica field.

Conversion to proved developed reserves. We converted approximately 486.2 Bcfe attributable to 76 PUDs into proved developed reserves and four PUDs into proved developed not producing.

Revision of prior reserve estimates. We experienced positive revisions of 193.9 Bcfe from 92 PUD locations, of which 95.3 Bcfe was due to an increase in well performance of offset producers, 39.0 Bcfe was a result of an increase in 2017 prices as compared to 2016 prices and 59.6 Bcfe was due to changes in our ownership interest. In addition, we also experienced downward revisions of 37.6 Bcfe due to downward performance revisions on 37 PUD locations. We also experienced downward revisions of 45.7 Bcfe due to changes in our drilling schedule, including the loss of five locations we operate and five locations operated by other operators. We also experienced downward revisions of 0.6 Bcfe due to the removal of two PUD locations in our Southern Louisiana fields that had not been drilled within five years of initial booking.

We drilled approximately 35% of our December 31, 2016 PUD locations during the year ended December 31, 2017.

Costs incurred relating to the development of PUDs were approximately $386.2 million in 2017. Estimated future development costs relating to the development of PUDs are projected to be approximately $551.0 million in 2018, $458.8 million in 2019, $514.5 million in 2020, $842.9 million in 2021 and $400.9 million in 2022.

All PUD drilling locations included in our 2017 reserve report are scheduled to be drilled within five years of initial booking.

As of December 31, 2017, 3% of our total proved reserves were classified as proved developed non-producing.

As noted above, our December 31, 2017 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 2017 of $51.34 per barrel and $2.98 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 2.9 Tcfe of our PUD volumes at December 31, 2017. 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 3.4 Tcfe of our PUD volumes at December 31, 2017.

Production, Prices and Production Costs

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

	2017	2016	2015
		($ In thousands)	
Natural gas sales			
Natural gas production volumes (MMcf)	350,061	227,594	156,151
Total natural gas sales	$ 845,999	$ 420,128	$ 324,733
Natural gas sales without the impact of derivatives ($/Mcf)	$ 2.42	$ 1.85	$ 2.08
Impact from settled derivatives ($/Mcf)	$ 0.07	$ 0.60	$ 0.71
Average natural gas sales price, including settled derivatives ($/Mcf)	$ 2.49	$ 2.45	$ 2.79
Oil and condensate sales			
Oil and condensate production volumes (MBbls)	2,579	2,126	2,899
Total oil and condensate sales	$ 124,568	$ 81,173	$ 122,615
Oil and condensate sales without the impact of derivatives ($/Bbl)	$ 48.29	$ 38.18	$ 42.29
Impact from settled derivatives ($/Bbl)	$ 1.59	$ 5.11	$ 3.12
Average oil and condensate sales price, including settled derivatives ($/Bbl)	$ 49.88	$ 43.29	$ 45.41
Natural gas liquids sales			
Natural gas liquids production volumes (MGal)	224,038	161,562	185,792
Total natural gas liquids sales	$ 136,057	$ 59,115	$ 58,129
Natural gas liquids sales without the impact of derivatives ($/Gal)	$ 0.61	$ 0.37	$ 0.31
Impact from settled derivatives ($/Gal)	$ (0.03)	$ (0.01)	$ —
Average natural gas liquids sales price, including settled derivatives ($/Gal)	$ 0.58	$ 0.36	$ 0.31
Natural gas, oil and condensate and natural gas liquids sales			
Natural gas equivalents (MMcfe)	397,543	263,430	200,089
Total natural gas, oil and condensate and natural gas liquids sales	$ 1,106,624	$ 560,416	$ 505,477
Natural gas, oil and condensate and natural gas liquids sales without the impact of derivatives ($/Mcfe)	$ 2.78	$ 2.13	$ 2.53
Impact from settled derivatives ($/Mcfe)	$ 0.07	$ 0.56	$ 0.60
Average natural gas, oil and condensate and natural gas liquids sales price, including settled derivatives ($/Mcfe)	$ 2.85	$ 2.69	$ 3.13
Production Costs:			
Average production costs (per Mcfe)	$ 0.20	$ 0.26	$ 0.35
Average production taxes and midstream costs (per Mcfe)	$ 0.68	$ 0.68	$ 0.77
Total production and midstream costs and production taxes (per Mcfe)	$ 0.88	$ 0.94	$ 1.12

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, 2017:

	Year Ended December 31,		
	2017	2016	2015
Utica Shale			
Net Production			
Oil (MBbls)	473	870	1,608
Natural gas (MMcf)	309,450	227,447	155,926
NGL (Mgal)	139,634	161,494	185,753
Total (MMcfe)	332,238	255,740	192,108
Average Sales Price Without the Impact of Derivatives:			
Oil (per Bbl)	$ 44.26	$ 34.59	$ 37.85
Natural gas (per Mcf)	$ 2.38	$ 1.85	$ 2.08
NGL (per Gal)	$ 0.60	$ 0.37	$ 0.31
Average Production Cost (per Mcfe)	$ 0.15	$ 0.18	$ 0.25

	Year Ended December 31,
	2017 (1)
SCOOP	
Net Production	
Oil (MBbls)	1,083
Natural gas (MMcf)	40,501
NGL (Mgal)	84,283
Total (MMcfe)	59,038
Average Sales Price Without the Impact of Derivatives:	
Oil (per Bbl)	$ 48.70
Natural gas (per Mcf)	$ 2.68
NGL (per Gal)	$ 0.62
Average Production Cost (per Mcfe)	$ 0.19

(1) We acquired our SCOOP assets in our SCOOP acquisition completed on February 17, 2017.

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, 2017.

Field	NRI/WI (1) Percentages	Productive Oil Wells Gross	Productive Oil Wells Net	Productive Gas Wells Gross	Productive Gas Wells Net	Non-Productive Oil Wells Gross	Non-Productive Oil Wells Net	Non-Productive Gas Wells Gross	Non-Productive Gas Wells Net	Developed Acreage (2) Gross	Developed Acreage (2) Net	Undeveloped Acreage Gross	Undeveloped Acreage Net
Utica Shale (3)	42.75/52.07	74	36.15	433	227.91	3	2.66	2	1.57	66,133	55,733	170,826	157,943
SCOOP (4)	30.83/38.52	365	109.96	45	35.88	25	14.76	12	10.96	38,182	38,182	12,226	12,226
West Cote Blanche Bay Field (5)	80.108/100	86	86	—	—	146	146	16	16	5,668	5,668	—	—
E. Hackberry Field (6)	82.33/100	17	17	—	—	130	130	—	—	2,910	2,910	1,206	1,206
W. Hackberry Field	87.5/100	2	2	—	—	12	12	—	—	726	726	306	306
Niobrara Formation (7)	34.52/48.61	3	1.46	—	—	—	—	—	—	1,460	730	5,473	2,653
Bakken Formation (8)	1.51/1.83	18	0.3	—	—	—	—	—	—	386	77	3,505	701
Overrides/Royalty Non-operated	Various	662	0.8	—	—	—	—	—	—	—	—	—	—
Total		1,227	253.67	478	263.79	316	305.42	30	28.53	115,465	104,026	193,542	175,035

(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Developed acres are acres spaced or assigned to productive wells. Approximately 37% of our acreage is developed acreage and has been perpetuated by production.
(3) With respect to our total undeveloped Utica Shale acreage as of December 31, 2017, leases representing 22%, 8%, 9% and 17% are currently scheduled to expire in 2018, 2019, 2020 and thereafter, respectively. 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 191 gross (29.15 net) gas wells and 29 gross (3.32 net) oil wells drilled by other operators on our acreage.
(4) With respect to our total undeveloped SCOOP acreage as of December 31, 2017, leases representing 6%, 67% and 5% are currently scheduled to expire in 2018, 2019 and 2020, respectively. NRI/WI is from wells that have been drilled or in which we have elected to participate. Includes one gross (.05 net) gas well and 239 gross (8.4 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 11% and 53% of our total Niobrara undeveloped acreage are currently scheduled to expire in 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.

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	81	81	77	77	72	72
Dry	—	—	—	—	—	—
Total	81	81	77	77	72	72
Development:						
Productive	124	115.4	49	42.5	49	38
Dry	2	2	1	1	—	—
Total	126	117.4	50	43.5	49	38
Exploratory:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total	—	—	—	—	—	—

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

In two separate complaints, one filed by the State of Louisiana and the Parish of Cameron in the 38th Judicial District Court for the Parish of Cameron on February 9, 2016 and the other filed by the State of Louisiana and the District Attorney for the 15th Judicial District of the State of Louisiana in the 15th Judicial District Court for the Parish of Vermilion on July 29, 2016, we were named as a defendant, among 26 oil and gas companies, in the Cameron Parish complaint and among more than 40 oil and gas companies in the Vermilion Parish complaint, or the Complaints. The Complaints were filed under the State and Local Coastal Resources Management Act of 1978, as amended, and the rules, regulations, orders and ordinances adopted thereunder, which we referred to collectively as the CZM Laws, and allege that certain of the defendants' oil and gas exploration, production and transportation operations associated with the development of the East Hackberry and West Hackberry oil and gas fields, in the case of the Cameron Parish complaint, and the Tigre Lagoon oil and gas field, in the case of the Vermilion Parish complaint, were conducted in violation of the CZM Laws. The Complaints allege that such activities caused substantial damage to land and waterbodies located in the coastal zone of the relevant Parish, including due to defendants' design, construction and use of waste pits and the alleged failure to properly close the waste pits and to clear, re-vegetate, detoxify and return the property affected to its original condition, as well as the defendants' alleged discharge of waste into the coastal zone. The Complaints also allege that the defendants' oil and gas activities have resulted in the dredging of numerous canals, which had a direct and significant impact on the state coastal waters within the relevant Parish and that the defendants, among other things, failed to design, construct and maintain these canals using the best practical techniques to prevent bank slumping, erosion and saltwater intrusion and to minimize the potential for inland movement of storm-generated surges, which activities allegedly have resulted in the erosion of marshes and the degradation of terrestrial and aquatic life therein. The Complaints also allege that the defendants failed to re-vegetate, refill, clean, detoxify and otherwise restore these canals to their original condition. In these two petitions, the plaintiffs seek damages and other appropriate relief under the CZM Laws, including the payment of costs necessary to clear, re-vegetate, detoxify and otherwise restore the affected coastal zone of the relevant Parish to its original condition, actual restoration of such coastal zone to its original condition, and the payment of reasonable attorney fees and legal expenses and pre-judgment and post judgment interest.

We were served with the Cameron complaint in early May 2016 and with the Vermilion Complaint in early September 2016. The Louisiana Attorney General and the Louisiana Department of Natural Resources intervened in both the Cameron Parish suit and the Vermilion Parish suit. Shortly after the Complaints were filed, certain defendants removed the cases to the lawsuit to the United States District Court for the Western District of Louisiana. In both cases, the plaintiffs have filed a motion to remand and the plaintiffs agreed to an extension of time for all defendants to file responsive pleadings until the District Courts ruled on the motions to remand. In the Vermilion Parish case, the District Court entered an order on September 26, 2017 remanding the lawsuit to the 15th Judicial District Court, State of Louisiana, Parish of Vermilion. In the Cameron Parish lawsuit, the federal magistrate, on January 18, 2018, issued a report and recommendation that the Cameron Parish lawsuit be remanded to the 38th Judicial District Court, State of Louisiana, Parish of Cameron. It is anticipated that one or more of the defendants will object to the magistrate's report and recommendation, in which case the report and recommendation will be reviewed by the District Court after additional briefing by the parties. Due the procedural posture of lawsuits, the fact that responsive pleadings have not been filed and the fact that the parties have not begun discovery, we have not had the opportunity to evaluate the applicability of the allegations made in plaintiffs' complaints to our operations and management cannot determine the amount of loss, if any, that may result.

In addition, 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
2016		
First Quarter	$ 31.05	$ 21.00
Second Quarter	34.67	26.00
Third Quarter	32.50	25.34
Fourth Quarter	30.47	21.30
2017		
First Quarter	$ 22.35	$ 15.66
Second Quarter	17.82	12.47
Third Quarter	15.09	10.90
Fourth Quarter	15.08	11.73

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Repurchases of Equity Securities

In January 2018, our board of directors approved a stock repurchase program to acquire up to $100.0 million of our outstanding common stock during 2018. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and will be subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require us to acquire any specific number of shares. We intend to purchase shares under the repurchase program opportunistically while maintaining sufficient liquidity to fund our 2018 capital development program. This repurchase program is authorized to extend through December 31, 2018 and may be suspended from time to time, modified, extended or discontinued by our board of directors at any time. We have not made any purchases of our common stock as of February 22, 2018.

Holders of Record

At the close of business on February 14, 2018, there were 349 stockholders of record holding 183,105,910 shares of our outstanding common stock. There were approximately 22,941 beneficial owners of our common stock as of February 14, 2018.

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, 2017, December 31, 2016 and December 31, 2015 and the selected consolidated balance sheet data at December 31, 2017 and December 31, 2016 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, 2014 and December 31, 2013 and the selected consolidated balance sheet data at December 31, 2015, December 31, 2014 and December 31, 2013 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,				
	2017	2016	2015	2014	2013
	(In thousands, except share data)				
Selected Consolidated Statements of Operations Data:					
Revenues	$ 1,320,303	$ 385,910	$ 708,990	$ 670,762	$ 262,225
Costs and expenses:					
Lease operating expenses	80,246	68,877	69,475	52,191	26,703
Production taxes	21,126	13,276	14,740	24,006	26,933
Midstream gathering and processing	248,995	165,972	138,590	64,467	11,030
Depreciation, depletion and amortization	364,629	245,974	337,694	265,431	118,880
Impairment of oil and natural gas properties	—	715,495	1,440,418	—	—
General and administrative	52,938	43,409	41,967	38,290	22,519
Accretion expense	1,611	1,057	820	761	717
Acquisition expense	2,392	—	—	—	—
(Gain) loss on sale of assets	—	—	—	(11)	508
	771,937	1,254,060	2,043,704	445,135	207,290
Income (Loss) from Operations	548,366	(868,150)	(1,334,714)	225,627	54,935
Other (Income) Expense:					
Interest expense	108,198	63,530	51,221	23,986	17,490
Interest income	(1,009)	(1,230)	(643)	(195)	(297)
Litigation settlement	—	—	—	25,500	—
Insurance proceeds	—	(5,718)	(10,015)	—	—
Loss on debt extinguishment	—	23,776	—	—	—
Gain on contribution of investments	—	—	—	(84,470)	—
Loss (income) from equity method investments	5,257	33,985	106,093	(139,434)	(213,058)
Other (income) expense	(1,041)	129	(485)	(504)	(528)
	111,405	114,472	146,171	(175,117)	(196,393)
Income (Loss) from Continuing Operations before Income Taxes	436,961	(982,622)	(1,480,885)	400,744	251,328
Income Tax Expense (Benefit)	1,809	(2,913)	(256,001)	153,341	98,136
Income (Loss) from Continuing Operations	435,152	(979,709)	(1,224,884)	247,403	153,192
Net Income (Loss) Available to Common Stockholders	$ 435,152	$ (979,709)	$ (1,224,884)	$ 247,403	$ 153,192
Net Income (Loss) Per Common Share—Basic:	$ 2.42	$ (7.97)	$ (12.27)	$ 2.90	$ 1.98
Net Income (Loss) Per Common Share—Diluted:	$ 2.41	$ (7.97)	$ (12.27)	$ 2.88	$ 1.97

	At December 31,				
	2017	2016	2015	2014	2013
	(In thousands)				
Selected Consolidated Balance Sheet Data:					
Total assets	$ 5,807,752	$ 4,223,145	$ 3,334,734	$ 3,619,473	$ 2,685,039
Total debt, including current maturity	$ 2,038,943	$ 1,593,875	$ 946,263	$ 703,564	$ 291,090
Total liabilities	$ 2,706,138	$ 2,039,253	$ 1,295,897	$ 1,323,177	$ 634,801
Stockholders' equity	$ 3,101,614	$ 2,183,892	$ 2,038,837	$ 2,296,296	$ 2,050,238

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 principal properties are located in the Utica Shale primarily in Eastern Ohio and the SCOOP Woodford and SCOOP Springer plans in Oklahoma. In addition, among other interests, we hold an acreage position along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, an acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, and an approximate 25.1% equity interest in Mammoth Energy Services, Inc., or Mammoth Energy, an oil field services company listed on the Nasdaq Global Select Market (TUSK).

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. During the last three years, particularly in light of the continued downturn in commodity prices, we focused on operational efficiencies in an effort to reduce our overall well costs and deliver better results in a more economical manner, all while growing our production base each year. In 2017, an increase in commodity prices allowed us to increase our capital budget as compared to 2016 and position us well to navigate the current commodity price environment. In response to current declining forward natural gas prices, we are focused on delivering growth within cash flow by exercising strict capital discipline and currently expect to reduce our planned capital expenditures by approximately 23% as compared to 2017.

2017 and 2018 Year to Date Highlights

- Production increased 51% to approximately 397,543 MMcfe for the year ended December 31, 2017 from approximately 263,430 MMcfe for the year ended December 31, 2016.
- On February 17, 2017, we, through our wholly-owned subsidiary Gulfport MidCon LLC, or Gulfport MidCon (formerly known as SCOOP Acquisition Company, LLC), completed our acquisition, which we refer to as our SCOOP acquisition, of certain assets from Vitruvian II Woodford, LLC, an unrelated third-party seller, for a total purchase price of approximately $1.85 billion, consisting of $1.35 billion in cash, subject to certain adjustments, and approximately 23.9 million shares of our common stock (of which approximately 5.2 million shares were placed in an indemnity escrow). Our SCOOP acquisition included approximately 46,000 net surface acres with multiple producing zones, including the Woodford and Springer formations in the South Central Oklahoma Oil Province, or SCOOP, resource play, in Grady, Stephens and Garvin Counties, Oklahoma.

- On June 5, 2017, we acquired approximately 2.0 million shares of Mammoth Energy common stock in connection with our contribution of all of our membership interests in Sturgeon Acquisitions LLC, Stingray Energy Services LLC and Stingray Cementing LLC, which we refer to as Sturgeon, Stingray Energy and Stingray Cementing, respectively, bringing our equity interest in Mammoth Energy to approximately 25.1%.

- During 2017, we spud 126 gross (117.4 net) wells, turned to sales 81 gross (72.1 net) operated wells, participated in an additional 57 gross (9.4 net) wells that were drilled by other operators on our Utica Shale and SCOOP acreage and recompleted 81 gross and net wells in our Southern Louisiana fields. Of our 126 new wells spud during 2017, 50 were completed as producing wells, two were non-productive and, at year end, 66 were in various stages of completion and eight were drilling.

- Oil and natural gas revenues, before the impact of derivatives, increased 97% to $1.1 billion for the year ended December 31, 2017 from $560.4 million for the year ended December 31, 2016.

- During the year ended December 31, 2017, we reduced our unit lease operating expense by 23% to $0.20 per Mcfe from $0.26 per Mcfe during the year ended December 31, 2016.

- During the year ended December 31, 2017, we reduced our unit general and administrative expense by 19% to $0.13 per Mcfe from $0.16 per Mcfe during the year ended December 31, 2016.

- On October 11, 2017, we issued $450.0 million in aggregate principal amount of our 6.375% Senior Notes due 2026, or the 2026 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. Interest on the 2026 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from October 11, 2017, payable semi-annually on January 15 and July 15 of each year, commencing on January 15, 2018. The 2026 Notes will mature on January 15, 2026. A portion of the net proceeds from the issuance of the 2026 Notes was used to repay all of our outstanding borrowings under our secured revolving credit facility on October 11, 2017 and the balance was used to fund the remaining outspend related to our 2017 capital development plans.

- In January 2018, our board of directors approved a stock repurchase program to acquire up to $100.0 million of our outstanding common stock during 2018, which we believe underscores the confidence we have in our business model, financial performance and asset base.

- During 2018 (through February 9, 2018), we spud 12 gross (9.8 net) wells. As of February 9, 2018, six wells were waiting on completion and six 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 $2.9 billion at December 31, 2017 and $1.6 billion at December 31, 2016. 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 $715.5 million for the year ended December 31, 2016. No ceiling test impairment was recognized by us for the year ended December 31, 2017. If prices of oil, natural gas and natural gas liquids decline in the future, 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, 2017 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, 2017, a valuation allowance of $298.8 million had been established for the net deferred tax asset, with the exception of certain NOLs that we expect to realize on a more likely than not basis. On December 22, 2017, the President of the United States signed into law the Tax Cuts and Jobs Act. Further information on the tax impacts of the Tax Cut and Jobs Act is included in Note 10 of our consolidated financial statements.

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.

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 years ended December 31, 2016 and 2015, we recognized an impairment loss related to our investment in Grizzly of approximately $23.1 million and $101.6 million, respectively.

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 using 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, 2017.

RESULTS OF OPERATIONS

Results of Operations

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

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

	2017	2016	2015
		($ In thousands)	
Natural gas sales			
Natural gas production volumes (MMcf)	350,061	227,594	156,151
Total natural gas sales	$ 845,999	$ 420,128	$ 324,733
Natural gas sales without the impact of derivatives ($/Mcf)	$ 2.42	$ 1.85	$ 2.08
Impact from settled derivatives ($/Mcf)	$ 0.07	$ 0.60	$ 0.71
Average natural gas sales price, including settled derivatives ($/Mcf)	$ 2.49	$ 2.45	$ 2.79
Oil and condensate sales			
Oil and condensate production volumes (MBbls)	2,579	2,126	2,899
Total oil and condensate sales	$ 124,568	$ 81,173	$ 122,615
Oil and condensate sales without the impact of derivatives ($/Bbl)	$ 48.29	$ 38.18	$ 42.29
Impact from settled derivatives ($/Bbl)	$ 1.59	$ 5.11	$ 3.12
Average oil and condensate sales price, including settled derivatives ($/Bbl)	$ 49.88	$ 43.29	$ 45.41
Natural gas liquids sales			
Natural gas liquids production volumes (MGal)	224,038	161,562	185,792
Total natural gas liquids sales	$ 136,057	$ 59,115	$ 58,129
Natural gas liquids sales without the impact of derivatives ($/Gal)	$ 0.61	$ 0.37	$ 0.31
Impact from settled derivatives ($/Gal)	$ (0.03)	$ (0.01)	$ —
Average natural gas liquids sales price, including settled derivatives ($/Gal)	$ 0.58	$ 0.36	$ 0.31
Natural gas, oil and condensate and natural gas liquids sales			
Natural gas equivalents (MMcfe)	397,543	263,430	200,089
Total natural gas, oil and condensate and natural gas liquids sales	$ 1,106,624	$ 560,416	$ 505,477
Natural gas, oil and condensate and natural gas liquids sales without the impact of derivatives ($/Mcfe)	$ 2.78	$ 2.13	$ 2.53
Impact from settled derivatives ($/Mcfe)	$ 0.07	$ 0.56	$ 0.60
Average natural gas, oil and condensate and natural gas liquids sales price, including settled derivatives ($/Mcfe)	$ 2.85	$ 2.69	$ 3.13
Production Costs:			
Average production costs (per Mcfe)	$ 0.20	$ 0.26	$ 0.35
Average production taxes and midstream costs (per Mcfe)	$ 0.68	$ 0.68	$ 0.77
Total production and midstream costs and production taxes (per Mcfe)	$ 0.88	$ 0.94	$ 1.12

The total volume hedged for 2017, 2016 and 2015 represented approximately 68%, 77% and 46%, respectively, of our total sales volumes for the applicable year.

From 2016 to 2017, our net equivalent gas production increased 51% from 263,430 MMcfe to 397,543 MMcfe primarily as a result of the continued development of our Utica Shale acreage and the acquisition of our SCOOP acreage. From 2015 to 2016, our net equivalent gas production increased 32% from 200,089 MMcfe to 263,430 MMcfe primarily as a result of the continued development of our Utica Shale acreage. We currently estimate that our 2018 production will be between 456,250 and 474,500 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. See Item 1A. "Risk Factors."

Comparison of the Years Ended December 31, 2017 and December 31, 2016

We reported net income of $435.2 million for the year ended December 31, 2017 as compared to a net loss of $979.7 million for the year ended December 31, 2016. This increase in period-to-period net income was due primarily to no impairment charge for the year ended December 31, 2017 as compared to a $715.5 million impairment of oil and natural gas properties for the year ended December 31, 2016 and a $934.4 million increase in oil and natural gas revenues, partially offset by an $83.0 million increase in midstream gathering and processing expenses, a $118.7 million increase in depreciation, depletion and amortization expense and a $44.7 million increase in interest expense for the year ended December 31, 2017, as compared to the year ended December 31, 2016.

Oil and Natural Gas Revenues. For the year ended December 31, 2017, we reported oil and natural gas revenues of $1.3 billion as compared to oil and natural gas revenues of $385.9 million during 2016. This $934.4 million, or 242%, increase in revenues was primarily attributable to the following:

- A $388.2 million increase in natural gas and oil sales due to a favorable change in gains and losses from derivative instruments. Of the total change, $512.1 million was due to favorable changes in the fair value of our open derivative positions in each period and $123.9 million was due to an unfavorable change in settlements related to our derivative positions.

- A $425.9 million increase in natural gas sales without the impact of derivatives due to a 54% increase in natural gas sales volumes and a 31% increase in natural gas market prices.

- A $43.4 million increase in oil and condensate sales without the impact of derivatives due to a 21% increase in oil and condensate sales volumes and a 26% increase in oil and condensate market prices.

- A $76.9 million increase in natural gas liquids sales without the impact of derivatives due to a 39% increase in natural gas liquids sales volumes and a 66% increase in natural gas liquids market prices.

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $80.2 million for the year ended December 31, 2017 from $68.9 million for the year ended December 31, 2016. This increase was mainly the result of an increase in expenses related to supervision and labor, overhead, surface rentals, water hauling and treatment, chemicals, ad valorem taxes and road, location and equipment repairs, partially offset by decreases in compression and water disposal. However, due to increased efficiencies and a 51% increase in our production volumes for the year ended December 31, 2017 as compared to the year ended December 31, 2016, our per unit LOE decreased by 23% from $0.26 per Mcfe to $0.20 per Mcfe.

Production Taxes. Production taxes increased to $21.1 million for the year ended December 31, 2017 from $13.3 million for 2016. This increase was primarily related to an increase in realized prices and production volumes.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased by $83.0 million to $249.0 million for the year ended December 31, 2017 from $166.0 million for 2016. This increase was primarily the result of midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2017 and 2016 drilling activities, as well as production volumes resulting from our SCOOP acquisition in February 2017.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $364.6 million for the year ended December 31, 2017, and consisted of $358.8 million in depletion of oil and natural gas properties and $5.8 million in depreciation of other property and equipment, as compared to total DD&A expense of $246.0

million for 2016. This increase was due to an increase in our full cost pool as a result of our SCOOP acquisition and 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 $52.9 million for the year ended December 31, 2017 from $43.4 million for the year ended December 31, 2016. This $9.5 million increase was due to an increase in salaries and benefits resulting from an increased number of employees, consulting fees, bank service charges, computer support and franchise taxes, partially offset by a decrease in employee stock compensation expense and legal fees. However, during the year ended December 31, 2017, we decreased our per unit general and administrative expense by 19% to $0.13 per Mcfe from $0.16 per Mcfe during the year ended December 31, 2016.

Accretion Expense. Accretion expense increased to $1.6 million for the years ended December 31, 2017 from $1.1 million for the year ended December 31, 2016, primarily as a result of our SCOOP acquisition.

Interest Expense. Interest expense increased to $108.2 million for the year ended December 31, 2017 from $63.5 million for the year ended December 31, 2016 due primarily to the issuance of $450.0 million of the 2026 Notes in October 2017 and the issuance of $600.0 million of the 2025 Notes in December 2016, partially offset by our repurchase or redemption of our 7.75% Senior Notes due 2020, which we refer to as the 2020 Notes, of which $600.0 million in aggregate principal amount was then outstanding, in October 2016 with the net proceeds from our issuance of $650.0 million of the 2024 Notes. In addition, total weighted debt outstanding under our revolving credit facility was $119.2 million for the year ended December 31, 2017 as compared to $0.2 million outstanding under such facility for 2016. Additionally, we capitalized approximately $9.5 million and $8.7 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2017 and December 31, 2016, respectively. This increase in capitalized interest in the 2017 period was primarily the result of our SCOOP acquisition and the development of this acreage.

Income Taxes. As of December 31, 2017, we had a net operating loss carry forward of approximately $574.4 million, in addition to numerous temporary differences, which gave rise to a net deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2017, a valuation allowance of $298.8 million had been provided against the net deferred tax asset, with the exception of certain state net operating losses that we expect to be able to utilize with NOL carrybacks. We recognized an income tax expense from continuing operations of $1.8 million for the year ended December 31, 2017.

Comparison of the Years Ended December 31, 2016 and December 31, 2015

We reported a net loss of $979.7 million for the year ended December 31, 2016 as compared to a net loss of $1.2 billion for the year ended December 31, 2015. This decrease in period-to-period net loss was due primarily to a $724.9 million decrease of impairment of oil and natural gas properties, a $91.7 million decrease in depreciation, depletion and amortization expense and a $72.1 million decrease in loss from equity method investments, partially offset by a $323.1 million decrease in oil and natural gas revenues, a $27.4 million increase in midstream gathering and processing expenses, a $23.8 million loss on debt extinguishment and a $253.1 million decrease in income tax benefit for the year ended December 31, 2016, as compared to the year ended December 31, 2015.

Oil and Gas Revenues. For the year ended December 31, 2016, we reported oil and natural gas revenues of $385.9 million as compared to oil and natural gas revenues of $709.0 million during 2015. This $323.1 million, or 46%, decrease in revenues was primarily attributable to the following:

- A $378.0 million decrease in natural gas and oil sales due to an unfavorable change in gains and losses from derivative instruments. Of the total change, $407.0 million was due to unfavorable changes in the fair value of our open derivative positions in each period and $29.0 million was due to a favorable change in settlements related to our derivative positions.

- A $95.4 million increase in natural gas sales without the impact of derivatives due to a 46% increase in natural gas sales volumes, partially offset by an 11% decrease in natural gas market prices.

- a $41.4 million decrease in oil and condensate sales without the impact of derivatives due to a 27% decrease in oil and condensate sales volumes and a 10% decrease in oil and condensate market prices.

- A $1.0 million increase in natural gas liquids sales without the impact of derivatives due to a 17% increase in natural gas liquids market prices, partially offset by a 13% decrease in natural gas liquids sales volumes.

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes decreased to $68.9 million for the year ended December 31, 2016 from $69.5 million for the year ended December 31, 2015. This decrease was mainly the result of a decrease in expenses related to contract labor and field supervision, field telemetry, facility repairs and maintenance and water disposal, partially offset by increases in water hauling, compression and ad valorem taxes.

Production Taxes. Production taxes decreased to $13.3 million for the year ended December 31, 2016 from $14.7 million for 2015. This decrease was primarily related to changes in our product mix and production location, as well as a decrease in commodity prices.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased by $27.4 million to $166.0 million for the year ended December 31, 2016 from $138.6 million for 2015. This increase was primarily the result of midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2016 and 2015 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense decreased to $246.0 million for the year ended December 31, 2016, and consisted of $243.1 million in depletion of oil and natural gas properties and $2.9 million in depreciation of other property and equipment, as compared to total DD&A expense of $337.7 million for 2015. This decrease was due to a decrease in our full cost pool as a result of our 2015 and 2016 ceiling test impairments and an increase in our total proved reserves volume used to calculate our total DD&A expense, partially offset by an increase in our production.

General and Administrative Expenses. Net general and administrative expenses increased to $43.4 million for the year ended December 31, 2016 from $42.0 million for the year ended December 31, 2015. This $1.4 million increase was due to an increase in salaries and benefits resulting from an increased number of employees, increases in fees for tax services, bank service charges, computer support, legal fees and consulting services, partially offset by a decrease in stock compensation expense.

Accretion Expense. Accretion expense increased to $1.1 million for the year ended December 31, 2016 from $0.8 million for the year ended December 31, 2015.

Interest Expense. Interest expense increased to $63.5 million for the year ended December 31, 2016 from $51.2 million for the year ended December 31, 2015 due primarily to the issuance of $350.0 million of 6.625% Senior Notes due 2023 on April 21, 2015 and the issuance of $600.0 million of the 2025 Notes on December 21, 2016, partially offset by our repurchase or redemption of the 2020 Notes in October 2016 with the net proceeds from our issuance of $650.0 million of the 2024 Notes. Total weighted debt outstanding under our revolving credit facility was $0.2 million for the year ended December 31, 2016 as compared to $46.6 million outstanding under such facility for 2015. Additionally, we capitalized approximately $8.7 million and $13.3 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2016 and December 31, 2015, respectively. This decrease in capitalized interest in the 2016 period was the result of changes to our development plan for our oil and natural gas properties.

Income Taxes. As of December 31, 2016, we had a net operating loss carry forward of approximately $463.1 million, in addition to numerous temporary differences, which gave rise to a net deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2016, a valuation allowance of $645.8 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 $4.7 million. We recognized an income tax benefit from continuing operations of $2.9 million for the year ended December 31, 2016.

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 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.

Our primary uses of cash are for ongoing business operations, repayments of our debt, capital expenditures, investments and acquisitions. During 2018, we also intend to purchase shares of our common stock under our recently announced stock repurchase program opportunistically with available funds while maintaining sufficient liquidity to fund our 2018 capital development program.

Net cash flow provided by operating activities was $679.9 million for the year ended December 31, 2017 as compared to net cash flow provided by operating activities of $337.8 million for 2016. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 60% increase in net revenues after giving effect to settled derivative instruments, partially offset by an increase in our operating expenses.

Net cash flow provided by operating activities was $337.8 million for the year ended December 31, 2016, as compared to net cash flow provided by operating activities of $322.2 million for 2015. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 13% increase in net revenues after giving effect to settled derivative instruments, partially offset by an increase in our operating expenses.

Net cash used in investing activities for the year ended December 31, 2017 was $2.3 billion as compared to $905.6 million for 2016. During the year ended December 31, 2017, we spent $1.1 billion in additions to oil and natural gas properties, of which $750.6 million was spent on our 2017 drilling and recompletion programs, $97.4 million was spent on expenses attributable to the wells spud, completed and recompleted during 2016, $1.5 million was spent on facility enhancements, $4.3 million was spent on plugging costs, $119.8 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale and the SCOOP and $7.2 million was spent on seismic with the remainder attributable mainly to future location development and capitalized general and administrative expenses. We also spent $1.3 billion to fund the cash portion of the purchase price for our SCOOP acquisition. In addition, $2.3 million was invested in Grizzly and $46.1 million was invested in Strike Force, net of distributions. We did not make any material investments in our our other equity investments during the year ended December 31, 2017. During the year ended December 31, 2017, we used cash from operations and proceeds from our 2016 equity and debt offerings and our 2017 debt offering for our investing activities.

Net cash used in investing activities for the year ended December 31, 2016 was $905.6 million as compared to $1.6 billion for 2015. During the year ended December 31, 2016, we spent $724.9 million in additions to oil and natural gas properties, of which $346.7 million was spent on our 2016 drilling and recompletion programs, $145.3 million was spent on expenses attributable to the wells spud, completed and recompleted during 2015, $4.3 million was spent on facility enhancements, $3.7 million was spent on plugging costs, $154.5 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, with the remainder attributable mainly to future location development and capitalized general and administrative expenses. In addition, $15.5 million was invested in Grizzly and $11.0 million was invested in Strike Force. We did not make any material investments in our other equity investments during the year ended December 31, 2016. We also received approximately $45.8 million from the sale of oil and gas properties, primarily the sale of non-producing leasehold acreage in the non-core area of our Utica acreage, and spent $185.0 million to fund the escrow deposit for our then pending SCOOP acquisition. During the year ended December 31, 2016, we used cash from operations and proceeds from our 2015 and 2016 equity and debt offerings for our investing activities.

Net cash provided by financing activities for the year ended December 31, 2017 was $433.0 million as compared to net cash provided by financing activities of $1.7 billion for 2016. The 2017 amount provided by financing activities is primarily attributable to the net proceeds of $444.3 million from our 2017 debt offering.

Net cash provided by financing activities for the year ended December 31, 2016 was $1.7 billion as compared to $1.2 billion for 2015. The 2016 amount provided by financing activities is primarily attributable to the net proceeds of $1.2 billion from our 2016 debt offerings, partially offset by the repurchase and redemption of our 2020 Notes, and net proceeds of $1.1 billion from our 2016 equity offerings.

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 December 13, 2021. As of December 31, 2017, we had a borrowing base of $1.2 billion, with an elected commitment of $1.0 billion, and no balance outstanding under our revolving credit facility. Total funds available for borrowing, after giving effect to an aggregate of $241.0 million of letters of credit, were $759.0 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; 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, 2017.

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, were 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 accrued 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 were senior unsecured obligations and ranked equally in the right of payment with all of our other senior indebtedness and were senior in right of payment to any of our future subordinated indebtedness. We had the option to 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 had the option to 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 had the option to 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 remained outstanding immediately after such redemption.

On October 6, 2016, we commenced a cash tender offer to purchase any and all of the 2020 Notes, which tender offer expired on October 13, 2016 and settled on October 14, 2016. Holders of the 2020 Notes that were validly tendered and accepted at or prior to the expiration time of the tender offer, or who delivered the 2020 Notes pursuant to the guaranteed delivery procedures, received total cash consideration of $1,042 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date. An aggregate of $403.5 million in principal amount of the 2020 Notes was validly tendered in the tender offer. The remaining 2020 Notes that were not tendered in the tender offer were redeemed by us. The redemption payment included approximately $196.5 million in aggregate principal amount at a redemption price of 103.875% of the principal amount of the redeemed 2020 Notes, plus accrued and unpaid interest thereon to the redemption date. Upon deposit of the redemption payment with the paying agent on October 14, 2016, the indenture governing the 2020 Notes was fully satisfied and discharged. The cash tender offer for the 2020 Notes and redemption of the remaining 2020 Notes were funded with the net proceeds from the offering of the 2024 Senior Notes (as discussed below) and cash on hand.

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.

On October 14, 2016, we issued the 2024 Notes in aggregate principal amount of $650.0 million. The 2024 Notes were issued under an indenture, dated as of October 14, 2016, among us, the subsidiary guarantors party thereto and the senior note indenture, to qualified institutional buyers pursuant to Rule 144A under the Securities Act, and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. Under this indenture, interest on the 2024 Notes accrues at a rate of 6.000% per annum on the outstanding principal amount thereof from October 14, 2016, payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2017. The 2024 Notes will mature on October 15, 2024. We received approximately $638.9 million in net proceeds from the offering of the 2024 Notes, which was used, together with cash on hand, to purchase the outstanding 2020 Notes in a concurrent cash tender offer, to pay fees and expenses thereof, and to redeem any of the 2020 Notes that remained outstanding after the completion of the tender offer.

On December 21, 2016, we issued $600.0 million in aggregate principal amount of 2025 Notes. The 2025 Notes were issued under an indenture, dated as of December 21, 2016, among us, the subsidiary guarantors party thereto and the senior note indenture, to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. Under this indenture, interest on the 2025 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from December 21, 2016, payable semi-annually on May 15 and November 15 of each year, commencing on May 15, 2017. The 2025 Notes will mature on May 15, 2025. We received approximately $584.7 million in net proceeds from the offering of the 2025 Notes, which we used, together with the net proceeds from our December 2016 offering of common stock and cash on hand, to fund the cash portion of the purchase price for our acquisition of certain assets of Vitruvian.

On October 11, 2017, we issued $450.0 million in aggregate principal amount of 2026 Notes. The 2026 Notes were issued under an indenture to qualified institutional buyers pursuant to Rule 144A under the Securities Act, and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. Under this indenture, interest on the 2026 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from October 11, 2017, payable semi-annually on January 15 and July 15 of each year, commencing on January 15, 2018. The 2026 Notes will mature on January 15, 2026. We received approximately $444.3 million in net proceeds from the offering of the 2026 Notes, a portion of which was used to repay all of our outstanding borrowings under our secured revolving credit facility on October 11, 2017 and the balance was used to fund the remaining outspend related to our 2017 capital development plans.

All of our existing and future restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt guarantee the 2023 Notes, 2024 Notes, 2025 Notes and the 2026 Notes, provided, however, that the 2023 Notes, 2024 Notes, 2025 Notes and 2026 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 2023 Notes, 2024 Notes, 2025 Notes and 2026 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 2023 Notes, 2024 Notes, 2025 Notes and 2026 Notes.

If we experience a change of control (as defined in the senior note indentures relating to the 2023 Notes, 2024 Notes, 2025 Notes and 2026 Notes), we will be required to make an offer to repurchase the 2023 Notes, 2024 Notes, 2025 Notes and 2026 Notes and 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 2023 Notes, 2024 Notes, 2025 Notes and 2026 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 2023 Notes, 2024 Notes, 2025 Notes and 2026 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, 2024 Notes, 2025 Notes and 2026 Notes, certain of these covenants are subject to termination upon the occurrence of certain events, including in the event the 2023 Notes, 2024 Notes, 2025 Notes and 2026 Notes are ranked as "investment grade" by Standard & Poor's and Moody's.

In connection with the issuance of the 2024 Notes, the 2025 Notes and 2026 Notes, we and our subsidiary guarantors entered into registration rights agreements, pursuant to which we agreed to file a registration statement with respect to an offer to exchange the 2024 Notes, the 2025 Notes and the 2026, as applicable, for new issues of substantially identical debt securities registered under the Securities Act. The exchange offers for the 2024 Notes and the 2025 Notes were completed on September 13, 2017. On January 18, 2018, we filed a registration statement on Form S-4 with respect to an offer to exchange the 2026 Notes for substantially identical debt securities registered under the Securities Act, which registration statement was declared effective by the SEC on February 12, 2018. We commenced the exchange offer relating to the 2026 notes on February 16, 2018, which we expect to close in March of 2018.

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, which was substantially completed in December 2016. The construction loan allows for maximum principal borrowings of $24.5 million and required us to fund 30% of the cost of the construction before any funds could 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 was 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, 2017, the total borrowings under the construction loan were approximately $23.7 million.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, acquisitions in the Utica Shale, our SCOOP acquisition in February 2017 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, 2017, 64.9% 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 2017, we spud 94 gross (88.7 net) and commenced sales from 68 gross (61.1 net) wells in the Utica Shale for a total cost of approximately $599.8 million. In addition, 26 gross (8.4 net) wells were drilled and 45 gross (9.3 net) wells were turned to sales by other operators on our Utica Shale acreage during 2017 for a total cost to us of approximately $114.8 million. We currently expect to drill 36 to 40 gross (26 to 29 net) horizontal wells and commence sales from 33 to 37 gross (33 to 37 net) horizontal wells on our Utica Shale acreage. As of February 9, 2018, we had three operated horizontal rigs drilling in the play and expect to release a rig in March of 2018 as our contract expires. We plan to run on average 2.5 operated horizontal rigs in the Utica Shale during 2018. We also anticipate an additional seven to eight net horizontal wells will be drilled, and sales commenced from nine to ten net horizontal wells, on our Utica Shale acreage by other operators. We currently anticipate our 2018 capital expenditures to be $425.0 million to $455.0 million related to our operated and non-operated Utica Shale activities.

During 2017, we spud 19 gross (15.7 net) and commenced sales from 13 gross (11.0 net) wells in the SCOOP for a total cost of approximately $250.0 million. In addition, 31 gross (0.9 net) wells were drilled and 23 gross (0.8 net) wells were turned to sales by other operators on our SCOOP acreage during 2017 for a total cost to us of approximately $7.0 million. During 2018, we currently expect to drill 15 to 16 gross (10 to 11 net) horizontal wells and commence sales from 20 to 22 gross (16 to 18 net) wells on our SCOOP acreage. We also anticipate four to five net wells will be drilled, and sales commenced from two to three net wells on our SCOOP acreage by other operators. As of February 9, 2018, we had four operated horizontal drilling rigs in the play and expect to release two rigs mid-summer 2018 as our contracts expire. We plan to run on average approximately three operated horizontal rigs in the SCOOP in 2018. We currently expect to spend $185.0 million to $210.0 million related to these activities for our operated and non-operated SCOOP acreage during 2018.

During 2017, we recompleted 60 existing wells and spud ten new wells at our WCBB field and recompleted 20 existing wells and spud five new wells in our Hackberry fields for a total aggregate cost of approximately $35.1 million. During 2018, we plan to run one completion rig in our Southern Louisiana fields. We currently expect to spend approximately $20.0 million in 2018 to perform recompletion activities in Southern Louisiana.

During 2017, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2018.

During the third quarter of 2006, we purchased a 24.9% interest in Grizzly. As of December 31, 2017, our net investment in Grizzly was approximately $57.6 million. Our capital requirements in 2017 for Grizzly were approximately $2.3 million. Effective October 5, 2012, Grizzly entered into a $125.0 million revolving credit facility, of which Grizzly paid the outstanding balance in full in July 2016. Gulfport paid its share of this amount on June 30, 2016. We do not currently anticipate any material capital expenditures in 2018 related to Grizzly's activities.

We had no material capital expenditures during the during the year ended December 31, 2017 related to our interests in Thailand. We do not currently anticipate any capital expenditures in Thailand in 2017.

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 years ended December 31, 2017 and 2016, we did not make any additional investments in these entities, and we do not currently anticipate any capital expenditures related to these entities in 2018. In the fourth quarter of 2014, we contributed our investments in Stingray Pressure, Stingray Logistics, Bison and Muskie to Mammoth, in exchange for a 30.5% limited partner interest in this newly formed limited partnership. On October 19, 2016, Mammoth Energy completed its IPO of 7,750,000 shares of its common stock at a public offering price of $15.00 per share, of which 7,500,000 shares were sold by Mammoth Energy and 250,000 shares were sold by certain selling stockholders, including 76,250 shares sold by us for which we received net proceeds of $1.1 million. Prior to the completion of the IPO, we were issued 9,150,000 shares of Mammoth Energy common stock in return for the contribution of our 30.5% interest in Mammoth. Following the IPO, we owned an approximate 24.2% interest in Mammoth Energy. On June 5, 2017, we acquired approximately 2.0 million shares of Mammoth Energy common stock in connection with our contribution of all of our membership interests in Sturgeon, Stingray Energy and Stingray Cementing, bringing our equity interest in Mammoth Energy to approximately 25.1%.

In February 2016, we, through our wholly-owned subsidiary Midstream Holdings, entered into an agreement with Rice to develop natural gas gathering assets in eastern Belmont County and Monroe County, Ohio, which we refer to as the dedicated areas, through an entity called Strike Force. We own a 25% interest in Strike Force, and EQT, following its acquisition of Rice, acts as operator and owns the remaining 75% interest in Strike Force. Construction of the gathering assets, which is ongoing, provides gathering services for wells operated by Gulfport and other operators and connectivity of existing dry gas gathering systems. First flow for Strike Force commenced on February 1, 2016. In connection with the formation of Strike Force, we contributed certain assets, including an approximately 11 mile-long, 12-inch diameter gathering line in 2016. During the year ended December 31, 2017, we paid $46.1 million in net cash calls related to Strike Force.

We currently expect to spend an aggregate of $140.0 million to $150.0 million in 2018 for non-drilling and completion activities, which includes acreage expenses, primarily lease extensions in the Utica Shale, and net cash contributions to Strike Force in 2018.

During 2015 and 2016, 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. We have successfully 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. In 2017, an increase in commodity prices allowed us to increase our capital budget as compared to 2016 and the resulting 2017 development activities enabled us to reach a size and scale, both financially and operationally, where we can navigate the current commodity price environment and adjust our business model accordingly. In response to current declining forward natural gas prices, we are focused on delivering growth within cash flow by exercising strict capital discipline and, as such, currently expect to reduce our planned capital expenditures by approximately 23% as compared to 2017.

Our total capital expenditures for 2018 are currently estimated to be in the range of $630.0 million to $685.0 million for drilling and completion expenditures. In addition, we currently expect to spend $140.0 million to $150.0 million in 2018 for non-drilling and completion expenditures, which includes acreage expenses, primarily lease extensions in the Utica Shale, and funding of our investment in Strike Force. Approximately 70% of our 2018 estimated drilling and completion capital expenditures are currently expected to be spent in the Utica Shale. The 2018 range of capital expenditures is lower than the $1.2 billion spent in 2017, primarily due to the decrease in current commodity prices, specifically natural gas prices, and our desire to fund our capital development program within cash flow.

In January 2018, our board of directors approved a stock repurchase program to acquire up to $100.0 million of our outstanding common stock during 2018. We intend to purchase shares under the repurchase program opportunistically with available funds while maintaining sufficient liquidity to fund our 2018 capital development program.

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, including the operations related to our pending acquisition. We believe that our strong liquidity position, hedge portfolio and conservative balance sheet position us well to react quickly to changing commodity prices and accelerate or decelerate our activity within the Utica Basin and the SCOOP as the market conditions warrant. Notwithstanding the foregoing, in the event commodity prices decline from current levels, 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 current low commodity price environment 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 2016, WTI prices ranged from $26.19 to $54.01 per barrel and the Henry Hub spot market price of natural gas ranged from $1.49 to $3.80 per MMBtu. During 2017, WTI prices ranged from $42.48 to $60.46 per barrel and the Henry Hub spot market price of natural gas ranged from $2.44 to $3.71 per MMBtu. 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, 2017.

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, 2017, the plugging and abandonment trust totaled approximately $3.1 million. At December 31, 2017, we have plugged 551 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

In January 2018, our board of directors approved a stock repurchase program to acquire up to $100.0 million of our outstanding common stock during 2018. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and will be subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require us to acquire any specific number of shares. We intend to purchase shares under the repurchase program opportunistically with available funds while maintaining sufficient liquidity to fund our 2018 capital development program. This repurchase program is authorized to extend through December 31, 2018 and may be suspended from time to time, modified, extended or discontinued by our board of directors at any time. We did not make any purchases of our common stock during the three months ended December 31, 2016 under any stock repurchase program or otherwise, and have not made any such purchases of our common stock as of February 22, 2018.

Contractual and Commercial Obligations

The following table sets forth our contractual and commercial obligations at December 31, 2017:

	Payment due by period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
6.625% senior unsecured notes due 2023 (1)	$ 477,531	$ 23,188	$ 46,375	$ 46,375	$ 361,593
6.000% senior unsecured notes due 2024 (2)	923,000	39,000	78,000	78,000	728,000
6.375% senior unsecured notes due 2025 (3)	886,998	38,250	76,500	76,500	695,748
6.375% senior unsecured notes due 2026 (4)	686,991	21,834	57,375	57,375	550,407
Asset retirement obligations	75,100	120	9,510	3,624	61,846
Building loan (5)	23,724	622	1,233	1,353	20,516
Firm transportation contracts	3,752,365	248,047	499,225	493,240	2,511,853
Purchase obligations (6)	39,330	39,330	—	—	—
Operating leases	190	136	54	—	—
Total	$ 6,865,229	$ 410,527	$ 768,272	$ 756,467	$ 4,929,963

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(1) 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 $11.6 million due thereafter.
(2) Includes estimated interest of $39.0 million due in less than one year; $78.0 million due in 1-3 years; $78.0 million due in 3-5 years and $78.1 million due thereafter.
(3) Includes estimated interest of $38.3 million due in less than one year; $76.5 million due in 1-3 years; $76.5 million due in 3-5 years and $95.7 million due thereafter.
(4) Includes estimated interest of $21.8 million due in less than one year; $57.4 million due in 1-3 years; $57.4 million due in 3-5 years and $100.4 million due thereafter.
(5) Does not include estimated interest of $1.1 million due in less than one year; $2.1 million due in 1-3 years: $1.9 million due in 3-5 years and $2.2 million due thereafter.
(6) 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, 2017.

New Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update, or 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. Subsequent to ASU 2014-09, the FASB issued several related ASU's to clarify the application of the revenue recognition standard. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years. The new standard permits retrospective application using either of the following methodologies: (i) restatement of each prior reporting period presented (full retrospective method) or (ii) recognition of a cumulative-effect adjustment as of the date of initial application (modified retrospective method). In July 2015, the FASB decided to defer the effective date by one year (until 2018). We have evaluated the impact of this ASU on our consolidated financial statements. This evaluation required, among other things, a review of existing contracts we have with our customers within each of the revenue streams identified within our business, including natural gas sales, oil and condensate sales and natural gas liquid sales. Substantially all of our revenue is earned pursuant to agreements under which we have currently interpreted one performance obligation, which is satisfied at a point-in-time. We did not identify any changes to our revenue recognition policies that would result in a material effect on the timing of our revenue recognition or its financial position, results of operations, net income or cash flows. Additionally, we do not believe further disaggregation of revenue will be required under the new standard. The adoption of this ASU will have an impact on our revenue related disclosures and internal controls over financial reporting as our revenue recognition related disclosures will expand upon adoption of the new standard. We are currently in the process of finalizing our documentation of new policies, procedures, systems, controls and data requirements as the standard is implemented. We will be in a position to begin reporting under the new standard beginning in the first quarter of 2018, using the modified retrospective method.

In February 2016, the FASB issued ASU No. 2016-02, *Leases*. The guidance requires the lessee to recognize most leases on the balance sheet thereby resulting in the recognition of lease assets and liability for those leases currently classified as operating leases. The accounting for lessors is largely unchanged. The guidance is effective for periods after December 15, 2018, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements and related disclosures and as contracts are reviewed under the new standard, this analysis could result in an impact to our financial statements; however, that impact is currently not known.

In March 2016, the FASB issued ASU No. 2016-05, *Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships.* The guidance was issued to clarify that change in the counterparty to a derivative instrument that had been designated as the hedging instrument under Topic 815, does not require designation of that hedging relationship provided that all other hedge accounting criteria continue to be met. We adopted the standard as of January 1, 2017. There was no impact on our consolidated financial statements because all current derivative instruments are not designated for hedge accounting.

In March 2016, the FASB issued ASU No. 2016-09, *Improvements to Employee Share-Based Payment Accounting*. This guidance was intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. We adopted the standard as of January 1, 2017. We elected to recognize forfeitures of awards as they occur. The adoption of this standard did not have a material impact on our consolidated financial statements.

In June 2016, the FASB issued ASU No. 2016-13, *Financial Instruments-Credit Losses: Measurement of Credit Losses on Financial Instruments*. This ASU amends guidance on reporting credit losses for assets held at amortized cost basis and available for sale debt securities. For assets held at amortized cost basis, this ASU eliminates the probable initial recognition threshold in current GAAP and instead, requires an entity to reflect its current estimate of all expected credit losses. The amendments affect loans, debt securities, trade receivables, net investments in leases, off balance sheet credit exposure, reinsurance receivables and any other financial assets not excluded from the scope that have the contractual right to receive cash. We are currently evaluating the impact this standard will have on our financial statements and related disclosures and do not anticipate it to have a material affect.

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments.* This guidance provides guidance of eight specific cash flow issues. This amendment is effective for periods after December 15, 2017, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, *Clarifying the Definition of a Business*. Under the current business combination guidance, there are three elements of a business: inputs, processes and outputs. The revised guidance adds an initial screen test to determine if substantially all of the fair value of the gross assets acquired is concentrated in a single asset or group of similar assets. If that screen is met, the set of assets is not a business. The new framework also specifies the minimum required inputs and processes necessary to be a business. This amendment is effective for periods after December 15, 2017, with early adoption permitted. We are in the process of evaluating the impact of this ASU 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 2016, WTI prices ranged from $26.19 to $54.01 per barrel and the Henry Hub spot market price of natural gas ranged from $1.49 to $3.80 per MMBtu. During 2017, WTI prices ranged from $42.48 to $60.46 per barrel and the Henry Hub spot market price of natural gas ranged from $2.44 to $3.71 per MMBtu. 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, 2017.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
2018	NYMEX Henry Hub	908,000	$ 3.06
2019	NYMEX Henry Hub	269,000	$ 2.93

	Location	Daily Volume (Bbls/day)	Weighted Average Price
2018	ARGUS LLS	1,500	$ 56.22
2018	NYMEX WTI	4,000	$ 52.20

	Location	Daily Volume (Bbls/day)	Weighted Average Price
2018	Mont Belvieu C3	3,500	$ 28.03
2018	Mont Belvieu C5	500	$ 46.62

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.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
January 2018 - March 2018	NYMEX Henry Hub	20,000	$ 2.91
April 2018 - March 2019	NYMEX Henry Hub	50,000	$ 3.13
April 2019 - December 2019	NYMEX Henry Hub	30,000	$ 3.10

For a portion of the natural gas fixed price swaps listed above, the counterparty has an option to extend the original terms an additional twelve months for the period January 2019 through December 2019. The option to extend the terms expires in December 2018. If executed, we would have additional fixed price swaps for 100,000 MMBtu per day at a weighted average price of $3.05.

In addition, we have entered into natural gas basis swap positions, which settle on the pricing index to basis differential of Tetco M2 to the NYMEX Henry Hub natural gas price. As of December 31, 2017, we had the following natural gas basis swap positions for Tetco M2.

	Location	Daily Volume (MMBtu/day)	Hedged Differential
2018	NPGL Mid-Continent	12,000	$ (0.26)

In January and February 2018, we entered into fixed price swaps for 2018 for approximately 1,000 barrels of oil per day at a weighted average price of $62.18 per barrel and for approximately 500 barrels of C3 propane per day at a weighted average price of $35.54 per barrel. For 2019, we entered into fixed price swaps for approximately 242,000 MMBtu of natural gas per day at a weighted average price of $2.79 per MMBtu and for approximately 2,000 barrels of oil per day at a weighted average price of $57.75 per barrel. Our fixed price swap contracts are tied to the commodity prices on NYMEX for natural gas, NYMEX WTI for oil and Mont Belvieu for propane. We will receive the fixed priced amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX for natural gas, NYMEX WTI for oil or Mont Belvieu for propane.

Under our 2018 contracts, we have hedged approximately 78% to 81% of our expected 2018 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, 2017, we had a net asset derivative position of $52.0 million as compared to a net liability derivative position of $136.8 million as of December 31, 2016, 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 $144.8 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $141.4 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Our revolving credit facility is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the eurodollar rates are elected, the eurodollar rates. At December 31, 2017, we had no variable interest rate borrowings outstanding; therefore, an increase in interest rates would not have impacted our interest expense. At October 11, 2017, the last day on which borrowings were outstanding under our revolving credit facility, such borrowings bore interest at the Eurodollar rate of 3.74%. A 1% increase in interest rates would have increased interest expense by approximately $1.2 million per year, based on $365.0 million in borrowings outstanding under our revolving credit facility as of that date. As of December 31, 2017, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

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

As of December 31, 2017, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and President and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and President and our Chief Financial Officer have concluded that, as of December 31, 2017, 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, 2017.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2017 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2017, as stated in their accompanying report.

/s/ Michael G. Moore		/s/ Keri Crowell	
Name:	Michael G. Moore	Name:	Keri Crowell
Title:	Chief Executive Officer and President	Title:	Chief Financial Officer

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Gulfport Energy Corporation (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, 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) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2017, and our report dated February 22, 2018 expressed an unqualified opinion on those financial statements.

Basis for opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and limitations of internal control over financial reporting

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.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 22, 2018

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.

(2) *Financial Statement Schedules*
All financial statement schedules have been omitted because they are not applicable or the required disclosure is presented in the financial statements or notes thereto.

(3) *Exhibits*

Exhibit Number	Description
2.1##	Purchase and Sale Agreement, dated as of December 13, 2016, by and among Gulfport Energy Corporation, SCOOP Acquisition Company, LLC and Vitruvian II Woodford, LLC (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 15, 2016).
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 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).
4.3	Indenture, dated as of October 14, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation's 6.000% Senior Notes due 2024) (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 19, 2016).
4.4	Indenture, dated as of December 21, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation's 6.375% Senior Notes due 2025) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 21, 2016).
4.5	Indenture, dated as of October 11, 2017, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation's 6.375% Senior Notes due 2026) (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 11, 2017).

4.6	Registration Rights Agreement, dated as of October 11, 2017, among Gulfport Energy Corporation, the subsidiary guarantors party and J.P. Morgan Securities LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 11, 2017).
4.7	Registration Rights Agreement, dated as of February 17, 2017, by and between Gulfport Energy Corporation and Vitruvian II Woodford, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 24, 2017).
4.8	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	Amended and Restated Credit Agreement, dated as of December 27, 2013, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 3, 2014).
10.9	First Amendment to Amended and Restated Credit Agreement, dated as of April 23, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 28, 2014).
10.10	Second Amendment to Amended and Restated Credit Agreement, dated as of November 26, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 3, 2014).
10.11	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).
10.12	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).
10.13	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).

10.14	Sixth Amendment, dated February 19, 2016, 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 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 5, 2016).
10.15	Seventh Amendment to Amended and Restated Credit Agreement, dated as of December 13, 2016, 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 the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 15, 2016).
10.16	Eighth Amendment to Amended and Restated Credit Agreement, entered into as of March 29, 2017, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent and L/C issuer, 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 4, 2017).
10.17	Ninth Amendment to Amended and Restated Credit Agreement, entered into as of May 4, 2017, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent and L/C issuer, the existing lenders named therein and JPMorgan Chase Bank, N.A., Commonwealth Bank of Australia, ABN, AMRO Capital USA LLC, Fifth Third Bank and Canadian Imperial Bank of Commerce, New York branch, as new lenders (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 9, 2017).
10.18	Tenth Amendment to Amended and Restated Credit Agreement, dated as of October 4, 2017, 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 the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 5, 2017).
10.19	Eleventh Amendment to Amended and Restated Credit Agreement, dated as of November 21, 2017, 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 the Form 8-K, File No. 000-19514, filed by the Company with the SEC on November 28, 2017).
10.20#	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).
10.21#	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).
10.22#	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).
10.23#	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.
10.24+	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-4, File No. 333-199905, filed by the Company with the SEC on November 6, 2014).
10.25+	Separation and Release Agreement by and between Gulfport Energy Corporation and Ross Kirtley entered into November 2, 2016 (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 3, 2016).
10.26+	Employment Agreement, entered into as of April 28, 2017, effective as of January 1, 2017, by and between Gulfport Energy Corporation and Keri Crowell (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 9, 2017).
10.27+	Employment Agreement, entered into as of April 28, 2017, effective as of January 1, 2017, by and between Gulfport Energy Corporation and Stuart Maier (incorporated by reference to Exhibit 10.4 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 9, 2017).
10.28+	Employment Agreement, entered into as of April 28, 2017, effective as of January 1, 2017, by and between Gulfport Energy Corporation and Steve Baldwin (incorporated by reference to Exhibit 10.5 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 9, 2017).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).

21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
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.

\## The schedules (or similar attachments) referenced in this agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule (or similar attachment) will be furnished supplementally to the Securities and Exchange Commission.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

Date: February 22, 2018

GULFPORT ENERGY CORPORATION

By: /s/ KERI CROWELL
Keri Crowell
Chief Financial Officer

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

Date:	February 22, 2018	By:	/s/ MICHAEL G. MOORE **Michael G. Moore** **Chief Executive Officer and President, Director** **(Principal Executive Officer)**
Date:	February 22, 2018	By:	/s/ DAVID L. HOUSTON **David L. Houston** **Chairman of the Board and Director**
Date:	February 22, 2018	By:	/s/ KERI CROWELL **Keri Crowell** **Chief Financial Officer** **(Principal Accounting and Financial Officer)**
Date:	February 22, 2018	By:	/s/ CRAIG GROESCHEL **Craig Groeschel** **Director**
Date:	February 22, 2018	By:	/s/ C. DOUG JOHNSON **C. Doug Johnson** **Director**
Date:	February 22, 2018	By:	/s/ BEN T. MORRIS **Ben T. Morris** **Director**
Date:	February 22, 2018	By:	/s/ SCOTT E. STRELLER **Scott E. Streller** **Director**
Date:	February 22, 2018	By:	/s/ PAUL WESTERMAN **Paul Westerman** **Director**

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive income (loss), stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company’s internal control over financial reporting as of December 31, 2017, 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 22, 2018 expressed an unqualified opinion.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2005.

Oklahoma City, Oklahoma
February 22, 2018

GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 99,557	$ 1,275,875
Restricted cash	—	185,000
Accounts receivable—oil and natural gas	182,213	136,761
Accounts receivable—related parties	—	16
Prepaid expenses and other current assets	4,912	3,135
Short-term derivative instruments	78,847	3,488
Total current assets	365,529	1,604,275
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $2,912,974 and $1,580,305 excluded from amortization in 2017 and 2016, respectively	9,169,156	6,071,920
Other property and equipment	86,754	68,986
Accumulated depletion, depreciation, amortization and impairment	(4,153,733)	(3,789,780)
Property and equipment, net	5,102,177	2,351,126
Other assets:		
Equity investments	302,112	243,920
Long-term derivative instruments	8,685	5,696
Deferred tax asset	1,208	4,692
Inventories	8,227	4,504
Other assets	19,814	8,932
Total other assets	340,046	267,744
Total assets	$ 5,807,752	$ 4,223,145
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 553,609	$ 265,124
Asset retirement obligation—current	120	195
Short-term derivative instruments	32,534	119,219
Current maturities of long-term debt	622	276
Total current liabilities	586,885	384,814
Long-term derivative instruments	2,989	26,759
Asset retirement obligation—long-term	74,980	34,081
Other non-current liabilities	2,963	—
Long-term debt, net of current maturities	2,038,321	1,593,599
Total liabilities	2,706,138	2,039,253
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, 183,105,910 issued and outstanding in 2017 and 158,829,816 in 2016	1,831	1,588
Paid-in capital	4,416,250	3,946,442
Accumulated other comprehensive loss	(40,539)	(53,058)
Retained deficit	(1,275,928)	(1,711,080)
Total stockholders' equity	3,101,614	2,183,892
Total liabilities and stockholders' equity	$ 5,807,752	$ 4,223,145

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
	2017	2016	2015
	(In thousands, except share data)		
Revenues:			
Natural gas sales	$ 845,999	$ 420,128	$ 324,733
Oil and condensate sales	124,568	81,173	122,615
Natural gas liquid sales	136,057	59,115	58,129
Net gain (loss) on natural gas, oil, and NGL derivatives	213,679	(174,506)	203,513
	1,320,303	385,910	708,990
Costs and expenses:			
Lease operating expenses	80,246	68,877	69,475
Production taxes	21,126	13,276	14,740
Midstream gathering and processing	248,995	165,972	138,590
Depreciation, depletion and amortization	364,629	245,974	337,694
Impairment of oil and natural gas properties	—	715,495	1,440,418
General and administrative	52,938	43,409	41,967
Accretion expense	1,611	1,057	820
Acquisition expense	2,392	—	—
	771,937	1,254,060	2,043,704
INCOME (LOSS) FROM OPERATIONS	548,366	(868,150)	(1,334,714)
OTHER (INCOME) EXPENSE:			
Interest expense	108,198	63,530	51,221
Interest income	(1,009)	(1,230)	(643)
Insurance proceeds	—	(5,718)	(10,015)
Loss on debt extinguishment	—	23,776	—
Loss from equity method investments, net	5,257	33,985	106,093
Other (income) expense	(1,041)	129	(485)
	111,405	114,472	146,171
INCOME (LOSS) BEFORE INCOME TAXES	436,961	(982,622)	(1,480,885)
INCOME TAX EXPENSE (BENEFIT)	1,809	(2,913)	(256,001)
NET INCOME (LOSS)	$ 435,152	$ (979,709)	$ (1,224,884)
NET INCOME (LOSS) PER COMMON SHARE:			
Basic	$ 2.42	$ (7.97)	$ (12.27)
Diluted	$ 2.41	$ (7.97)	$ (12.27)
Weighted average common shares outstanding—Basic	179,834,146	122,952,866	99,792,401
Weighted average common shares outstanding—Diluted	180,253,024	122,952,866	99,792,401

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	For the Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Net income (loss)	$ 435,152	$ (979,709)	$ (1,224,884)
Foreign currency translation adjustment (1)	12,519	2,119	(28,502)
Other comprehensive income (loss)	12,519	2,119	(28,502)
Comprehensive income (loss)	$ 447,671	$ (977,590)	$ (1,253,386)

(1) Net of $1.3 million in taxes for the year ended December 31, 2016. No taxes were recorded for the years ended December 31, 2017 and December 31, 2015.

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock									
	Shares	Amount		Paid-in Capital		Accumulated Other Comprehensive Loss		Retained Earnings (Deficit)		Total Stockholders' Equity
	(In thousands, except share data)									
Balance at January 1, 2015	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
Net loss	—		—		—		—		(979,709)	(979,709)
Other Comprehensive Income	—		—		—		2,119		—	2,119
Stock Compensation	—		—		12,251		—		—	12,251
Issuance of Common Stock in public offerings, net of related expenses	50,255,000		503		1,109,891		—		—	1,110,394
Issuance of Restricted Stock	252,566		3		(3)		—		—	—
Balance at December 31, 2016	158,829,816		1,588		3,946,442		(53,058)		(1,711,080)	2,183,892
Net income	—		—		—		—		435,152	435,152
Other Comprehensive Income	—		—		—		12,519		—	12,519
Stock Compensation	—		—		10,615		—		—	10,615
Issuance of Common Stock for the Vitruvian Acquisition, net of related expenses	23,852,117		239		459,197		—		—	459,436
Issuance of Restricted Stock	423,977		4		(4)		—		—	—
Balance at December 31, 2017	183,105,910	$	1,831	$	4,416,250	$	(40,539)	$	(1,275,928)	$ 3,101,614

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2017	2016	2015
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$ 435,152	$ (979,709)	$ (1,224,884)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Accretion of discount—Asset Retirement Obligation	1,611	1,057	820
Depletion, depreciation and amortization	364,629	245,974	337,694
Impairment of oil and gas properties	—	715,495	1,440,418
Stock-based compensation expense	6,369	7,351	8,616
Loss from equity investments	5,990	34,397	113,120
Gain on debt extinguishment	—	(1,108)	—
Change in fair value of derivative instruments	(188,802)	323,303	(83,671)
Deferred income tax expense (benefit)	1,690	18,188	(254,493)
Amortization of loan commitment fees	5,011	3,660	3,219
Amortization of note discount and premium	—	(1,716)	(2,165)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(45,452)	(64,889)	31,986
Decrease in accounts receivable—related party	16	—	30
Increase in prepaid expenses	(1,777)	(3,734)	(191)
Increase in other assets	(7,866)	—	—
Increase (decrease) in accounts payable and accrued liabilities and other	106,375	43,763	(47,199)
Settlement of asset retirement obligation	(3,057)	(4,189)	(1,121)
Net cash provided by operating activities	679,889	337,843	322,179
Cash flows from investing activities:			
Deductions to cash held in escrow	8	8	8
Additions to other property and equipment	(19,372)	(33,152)	(13,572)
Acquisitions of oil and natural gas properties	(1,348,657)	—	—
Additions to oil and natural gas properties	(1,064,678)	(724,925)	(1,579,129)
Proceeds from sale of oil and gas properties	4,866	45,812	27,998
Proceeds from sale of other property and equipment	1,569	—	—
Contributions to equity method investments	(55,280)	(26,472)	(14,472)
Distributions from equity method investments	7,376	18,147	4,914
Funding of restricted cash	185,000	(185,000)	—
Net cash used in investing activities	(2,289,168)	(905,582)	(1,574,253)
Cash flows from financing activities:			
Principal payments on borrowings	(365,276)	(87,685)	(350,172)
Borrowings on line of credit	365,000	86,000	250,000
Proceeds from bond issuance	450,000	1,250,000	350,000
Repayment of bonds	—	(624,561)	—
Borrowings on term loan	2,951	21,049	—
Debt issuance costs and loan commitment fees	(14,350)	(24,718)	(8,688)
Proceeds from issuance of common stock, net of offering costs and exercise of stock options	(5,364)	1,110,555	981,568
Net cash provided by financing activities	432,961	1,730,640	1,222,708
Net (decrease) increase in cash and cash equivalents	(1,176,318)	1,162,901	(29,366)
Cash and cash equivalents at beginning of period	1,275,875	112,974	142,340
Cash and cash equivalents at end of period	$ 99,557	$ 1,275,875	$ 112,974
Supplemental disclosure of cash flow information:			
Interest payments	$ 101,958	$ 68,966	$ 59,736
Income tax (receipts) payments	$ (1,105)	$ (19,770)	$ 16,156
Supplemental disclosure of non-cash transactions:			
Capitalized stock based compensation	$ 4,246	$ 4,900	$ 5,743
Asset retirement obligation capitalized	$ 42,270	$ 10,971	$ 8,800
Interest capitalized	$ 9,470	$ 9,148	$ 13,580
Foreign currency translation gain (loss) on equity method investments	$ 12,519	$ 3,468	$ (28,502)

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2017, 2016 AND 2015

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 the SCOOP Woodford and SCOOP Springer plays in Oklahoma. The Company also holds an acreage position along the Louisiana Gulf Coast in the West Cote Blanche Bay and Hackberry fields and 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., Gulfport Appalachia LLC, Gulfport Midstream Holdings, LLC, and Gulfport MidCon, 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 natural 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, 2017 and December 31, 2016.

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 2017, 2016 and 2015, 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. The Company did not recognize a ceiling test impairment for the year ended December 31, 2017.

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 approximately $2.9 billion and $1.6 billion at December 31, 2017 and December 31, 2016, 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. In addition, the Company has an equity investment in a U.S. company that has a subsidiary that is a Canadian entity whose functional currency is the Canadian dollar. 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, exclusive of taxes.

		(In thousands)
December 31, 2014	$	(26,675)
December 31, 2015	$	(55,175)
December 31, 2016	$	(51,709)
December 31, 2017	$	(39,190)

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 2003 – 2016 U.S. federal and 1997 - 2016 state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2017, 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.

On December 22, 2017, the President of the United States signed into law the Tax Cuts and Jobs Act ("Tax Act"). Further information on the tax impacts of the Tax Act is included in Note 10 of 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, 2017 and 2016, the Company had a gas imbalance receivable of approximately $0.2 million. 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.

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. The Company recognized impairment charges of $23.1 million and $101.6 million related to its investment in Grizzly Oil Sands ULC for the years ended December 31, 2016 and December 31, 2015, respectively. There was no impairment charge recorded for the year ended December 31, 2017.

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 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 restricted shares range between one to four years with 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, the fair value determination of acquired assets and liabilities 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 and related disclosures to conform to current period presentation. These reclassifications have no impact on previous reported total assets, total liabilities, net income (loss) or total operating cash flows.

Recent Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update ("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. Subsequent to ASU 2014-09, the FASB issued several related ASU's to clarify the application of the revenue recognition standard. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years. The new standard permits retrospective application using either of the following methodologies: (i) restatement of each prior reporting period presented (full retrospective method) or (ii) recognition of a cumulative-effect adjustment as of the date of initial application (modified retrospective method). In July 2015, the FASB decided to defer the effective date by one year (until 2018). The Company has evaluated the impact of this ASU on its consolidated financial statements. This evaluation required, among other things, a review of existing contracts the Company has with its customers within each of the revenue streams identified within its business, including natural gas sales, oil and condensate sales and natural gas liquid sales. Substantially all of the Company's revenue is earned pursuant to agreements under which it has currently interpreted one performance obligation, which is satisfied at a point-in-time. The Company did not identify any changes to its revenue recognition policies that would result in a material effect on the timing of the Company's revenue recognition or its financial position, results of operations, net income or cash flows. Additionally, the Company does not believe further disaggregation of revenue will be required under the new standard. The adoption of this ASU will have an impact on the Company's revenue related disclosures and internal controls over financial reporting as the Company's revenue recognition related disclosures will expand upon adoption of the new standard. The Company is currently in the process of finalizing documentation of new policies, procedures, systems, controls and data requirements as the standard is implemented. The Company will be in a position to begin reporting under the new standard beginning in the first quarter of 2018, using the modified retrospective method.

In February 2016, the FASB issued ASU No. 2016-02, *Leases*. The guidance requires the lessee to recognize most leases on the balance sheet thereby resulting in the recognition of lease assets and liability for those leases currently classified as operating leases. The accounting for lessors is largely unchanged. The guidance is effective for periods after December 15, 2018, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements and related disclosures and as contracts are reviewed under the new standard, this analysis could result in an impact to the Company's financial statements; however, that impact is currently not known.

In March 2016, the FASB issued ASU No. 2016-05, *Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships.* The guidance was issued to clarify that change in the counterparty to a derivative instrument that had been designated as the hedging instrument under Topic 815, does not require designation of that hedging relationship provided that all other hedge accounting criteria continue to be met. The Company adopted the standard as of January 1, 2017. There was no impact on the Company's consolidated financial statements because all current derivative instruments are not designated for hedge accounting.

In March 2016, the FASB issued ASU No. 2016-09, *Improvements to Employee Share-Based Payment Accounting*. This guidance was intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. The Company adopted the standard as of January 1, 2017. The Company has elected to recognize forfeitures of awards as they occur. The adoption of this standard did not have a material impact on the Company's consolidated financial statements.

In June 2016, the FASB issued ASU No. 2016-13, *Financial Instruments-Credit Losses: Measurement of Credit Losses on Financial Instruments*. This ASU amends guidance on reporting credit losses for assets held at amortized cost basis and available for sale debt securities. For assets held at amortized cost basis, this ASU eliminates the probable initial recognition threshold in current GAAP and instead, requires an entity to reflect its current estimate of all expected credit losses. The amendments affect loans, debt securities, trade receivables, net investments in leases, off balance sheet credit exposure, reinsurance receivables and any other financial assets not excluded from the scope that have the contractual right to receive cash. The Company is currently evaluating the impact this standard will have on its financial statements and related disclosures and does not anticipate it to have a material affect.

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments*. This guidance provides guidance of eight specific cash flow issues. This amendment is effective for periods after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, *Clarifying the Definition of a Business*. Under the current business combination guidance, there are three elements of a business: inputs, processes and outputs. The revised guidance adds an initial screen test to determine if substantially all of the fair value of the gross assets acquired is concentrated in a single asset or group of similar assets. If that screen is met, the set of assets is not a business. The new framework also specifies the minimum required inputs and processes necessary to be a business. This amendment is effective for periods after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact of this ASU on its consolidated financial statements.

2. ACQUISITIONS

In December 2016, the Company, through its wholly-owned subsidiary Gulfport MidCon LLC (“Gulfport MidCon”) (formerly known as SCOOP Acquisition Company, LLC), entered into an agreement to acquire certain assets of Vitruvian II Woodford, LLC (“Vitruvian”), an unrelated third-party seller (the “Vitruvian Acquisition”). The assets included in the Vitruvian Acquisition include 46,400 net surface acres located in Grady, Stephens and Garvin Counties, Oklahoma. On February 17, 2017, the Company completed the Vitruvian Acquisition for a total initial purchase price of approximately $1.85 billion, consisting of $1.35 billion in cash, subject to certain adjustments, and approximately 23.9 million shares of the Company’s common stock (of which approximately 5.2 million shares were placed in an indemnity escrow). The cash portion of the purchase price was funded with the net proceeds from the December 2016 common stock and senior note offerings and cash on hand. Acquisition costs of $2.4 million were incurred during the year ended December 31, 2017 related to the Vitruvian Acquisition.

Allocation of Purchase Price

The Vitruvian 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 February 17, 2017 acquisition date. The fair value of the assets acquired and liabilities assumed 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 Vitruvian 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 by the Company in the Vitruvian Acquisition to acquire the properties and the fair value amount of the assets acquired as of February 17, 2017.

		(In thousands)
Consideration:		
Cash, net of purchase price adjustments	$	1,354,093
Fair value of Gulfport's common stock issued		464,639
Total Consideration	$	1,818,732
Estimated Fair value of identifiable assets acquired and liabilities assumed:		
Oil and natural gas properties		
Proved properties	$	362,264
Unproved properties		1,462,957
Asset retirement obligations		(6,489)
Total fair value of net identifiable assets acquired	$	1,818,732

The equity consideration included in the initial purchase price was based on an equity offering price of $20.96 on December 15, 2016. The decrease in the price of Gulfport's common stock from $20.96 on December 15, 2016 to $19.48 on February 17, 2017 resulted in a decrease to the fair value of the total consideration paid as compared to the initial purchase price of approximately $35.3 million, which resulted in a closing date fair value lower than the initial purchase price.

Post-Acquisition Operating Results

For the period from the acquisition date of February 17, 2017 to December 31, 2017, the assets acquired in the Vitruvian Acquisition have contributed the following amounts of revenue to the Company's consolidated statements of operations. The amount of net income contributed by the assets acquired is not presented below as it is impracticable to calculate due to the Company integrating the acquired assets into its overall operations using the full cost method of accounting.

		Period from February 17, 2017 to December 31, 2017
		(In thousands)
Revenue	$	213,368

Pro Forma Information (Unaudited)

The following unaudited pro forma combined financial information presents the Company's results as though the Vitruvian Acquisition had been completed at January 1, 2016. The pro forma combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the Vitruvian Acquisition taken place on January 1, 2016; furthermore, the financial information is not intended to be a projection of future results.

	December 31,			
	2017		2016	
	(In thousands, except share data)			
Pro forma revenue	$	1,356,202	$	523,097
Pro forma net income (loss)	$	448,398	$	(1,190,481)
Pro forma earnings (loss) per share (basic)	$	2.49	$	(8.11)
Pro forma earnings (loss) per share (diluted)	$	2.49	$	(8.11)

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2017 and 2016 are as follows:

	December 31,	
	2017	2016
	(In thousands)	
Oil and natural gas properties	$ 9,169,156	$ 6,071,920
Office furniture and fixtures	37,369	21,204
Building	44,565	42,530
Land	4,820	5,252
Total property and equipment	9,255,910	6,140,906
Accumulated depletion, depreciation, amortization and impairment	(4,153,733)	(3,789,780)
Property and equipment, net	$ 5,102,177	$ 2,351,126

No impairment of oil and natural gas properties was required under the ceiling test for the year ended December 31, 2017. At December 31, 2016 and 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 years ended December 31, 2016 and 2015, respectively. 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 $715.5 million and $1.4 billion for the years ended December 31, 2016 and 2015, respectively.

Included in oil and natural gas properties at December 31, 2017 and 2016 is the cumulative capitalization of $165.6 million and $129.9 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 $35.7 million, $29.3 million and $27.9 million for the years ended December 31, 2017, 2016 and 2015, respectively. The average depletion rate per Mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $0.90, $0.92 and $1.68 per Mcfe for the years ended December 31, 2017, 2016 and 2015, respectively.

The following is a summary of Gulfport’s oil and natural gas properties not subject to amortization as of December 31, 2017:

	Costs Incurred in				
	2017	2016	2015	Prior to 2015	Total
	(In thousands)				
Acquisition costs	$ 1,511,685	$ 129,741	$ 429,897	$ 824,363	$ 2,895,686
Exploration costs	—	—	—	—	—
Development costs	5,076	4,607	3,635	2,214	15,532
Capitalized interest	3,871	(536)	(1,141)	(438)	1,756
Total oil and natural gas properties not subject to amortization	$ 1,520,632	$ 133,812	$ 432,391	$ 826,139	$ 2,912,974

The following table summarizes the Company’s non-producing properties excluded from amortization by area as of December 31, 2017:

	December 31, 2017
	(In thousands)
Utica	$ 1,513,452
MidContinent	1,396,642
Niobrara	2,184
Southern Louisiana	552
Bakken	99
Other	45
	$ 2,912,974

As of December 31, 2016, approximately $1.6 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 in the Utica Shale 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, 2017 and 2016 is as follows:

	December 31,	
	2017	2016
	(In thousands)	
Asset retirement obligation, beginning of period	$ 34,276	$ 26,437
Liabilities incurred	16,300	10,971
Liabilities settled	(3,057)	(4,189)
Accretion expense	1,611	1,057
Revisions in estimated cash flows	25,970	—
Asset retirement obligation as of end of period	75,100	34,276
Less current portion	120	195
Asset retirement obligation, long-term	$ 74,980	$ 34,081

4. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2017 and 2016:

	Approximate Ownership %	Carrying Value December 31, 2017	Carrying Value December 31, 2016	Loss (income) from equity method investments For the Year Ended December 31, 2017	2016	2015
				(In thousands)		
Investment in Tatex Thailand II, LLC	23.5%	$ —	$ —	$ (549)	$ (412)	$ 189
Investment in Tatex Thailand III, LLC	17.9%	—	—	(183)	—	—
Investment in Grizzly Oil Sands ULC	24.9999%	57,641	45,213	2,189	25,150	115,544
Investment in Timber Wolf Terminals LLC	50.0%	983	991	8	8	14
Investment in Windsor Midstream LLC	22.5%	30	25,749	25,233	(13,618)	(18,398)
Investment in Stingray Cementing LLC[(1)]	—%	—	1,920	205	263	147
Investment in Blackhawk Midstream LLC	48.5%	—	—	—	—	(7,216)
Investment in Stingray Energy Services LLC[(1)]	—%	—	4,215	282	1,044	557
Investment in Sturgeon Acquisitions LLC[(1)]	—%	—	20,526	(71)	993	(1,229)
Investment in Mammoth Energy Services, Inc.[(1)]	25.1%	165,715	111,717	(23,811)	20,646	16,485
Investment in Strike Force Midstream LLC	25.0%	77,743	33,589	1,954	(89)	—
		$ 302,112	$ 243,920	$ 5,257	$ 33,985	$ 106,093

(1) On June 5, 2017, the Company contributed all of its membership interests in Stingray Cementing LLC, Stingray Energy Services LLC and Sturgeon Acquisitions LLC to Mammoth Energy Services, Inc. ("Mammoth Energy"). See below under *Mammoth Energy Partners LP/Mammoth Energy Services, Inc.* for information regarding these transactions.

The tables below summarize financial information for the Company's equity investments, as of December 31, 2017 and 2016.

Summarized balance sheet information:

	December 31, 2017	December 31, 2016
	(In thousands)	
Current assets	$ 415,032	$ 148,733
Noncurrent assets	$ 1,542,090	$ 1,305,407
Current liabilities	$ 261,086	$ 57,173
Noncurrent liabilities	$ 148,839	$ 67,680

Summarized results of operations:

	December 31, 2017	2016	2015
	(In thousands)		
Gross revenue	$ 755,374	$ 287,733	$ 430,729
Net (loss) income	$ (37,102)	$ (65,070)	$ 16,761

Tatex Thailand II, LLC

The Company has an indirect ownership interest in Tatex Thailand II, LLC (“Tatex”). Tatex holds an 8.5% interest in 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 180,000 acres which includes the Phu Horm Field. The Company received $0.5 million and $0.4 million in distributions from Tatex II during the years ended December 31, 2017 and 2016, respectively.

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. 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. In December 2017, Tatex III was dissolved and the Company received a final distribution of $0.2 million.

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, 2017, Grizzly had approximately 830,000 acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. Grizzly has high-graded three oil sands projects to various stages of development. Grizzly commenced commercial production from its Algar Lake Phase I steam-assisted gravity drainage ("SAGD") oil sand project during the second quarter of 2014 and has regulatory approval for up to 11,300 barrels per day of bitumen production. Algar Lake production peaked at 2,200 barrels per day during the ramp-up phase of the SAGD facility, however, in April 2015, Grizzly made the decision to suspend operations at its Algar Lake facility due to the commodity price drop and its effect on project economics. Grizzly continues to monitor market conditions as it assesses start up plans for the facility. The Company reviewed its investment in Grizzly as of September 30, 2015 and December 31, 2015, and again at March 31, 2016, 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 and $23.1 million for the year ended December 31, 2016, which is included in loss from equity method investments, net in the accompanying consolidated statements of operations. As of and during the period ended December 31, 2017, commodity prices had increased as compared to the quarter ended March 31, 2016, and there were no impairment indicators that required further evaluation for impairment. If commodity prices decline in the future however, further impairment of the investment in Grizzly may be necessary. During the years ended December 31, 2017 and 2016, Gulfport paid $2.3 million and $15.5 million, respectively, in cash calls. Grizzly’s functional currency is the Canadian dollar. The Company's investment in Grizzly was increased by $12.3 million and $4.2 million as a result of a foreign currency translation gain and decreased by $28.5 million as a result of a foreign currency translation loss for the years ended December 31, 2017, 2016, and 2015, respectively.

Effective October 5, 2012, Grizzly entered into a $125.0 million revolving credit facility, of which Grizzly paid the outstanding balance in full in July 2016. Gulfport paid its share of this amount on June 30, 2016.

Timber Wolf Terminals LLC

During 2012, the Company invested in Timber Wolf Terminals LLC (“Timber Wolf”). Timber Wolf was formed to operate a crude/condensate terminal and a sand transloading facility in Ohio. During the years ended December 31, 2017 and 2016, the Company paid no cash calls to Timber Wolf.

Windsor Midstream LLC

At December 31, 2017, the Company held a 22.5% interest in Windsor Midstream LLC (“Midstream”), an entity controlled and managed by an unrelated third party. Midstream previously 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"). As a result of the sale of Coronado to EnLink, Midstream received common units of EnLink, which were subsequently sold by Midstream. During the year ended December 31, 2017, the Company was informed that Midstream had not recorded certain activity and fair value treatment of Midstream's investment in EnLink common units in a timely manner. The corresponding effect of this treatment was immaterial to the Company's previously issued financial statements and the recording of the correction in the current periods' financial statements was not material to the Company's estimated net income for the current full fiscal year. For the year ended December 31, 2017, approximately $23.4 million of the loss from equity method investments, net was related to the out-of-period activity associated with the accounting for Midstream's investment in EnLink common units. The Company received $0.5 million and $15.8 million in distributions from Midstream during the years ended December 31, 2017 and 2016, respectively.

Stingray Cementing LLC

During 2012, the Company invested in Stingray Cementing LLC ("Stingray Cementing"). Stingray Cementing provides well cementing services. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations. On June 5, 2017, the Company contributed all of its membership interests in Stingray Cementing to Mammoth Energy. See below under *Mammoth Energy Partners LP/Mammoth Energy Services, Inc.* for information regarding this transaction.

Blackhawk Midstream LLC

During 2012, the Company invested in Blackhawk Midstream LLC ("Blackhawk"). Blackhawk coordinated gathering, compression, processing and marketing activities for the Company in connection with the development of its Utica Shale acreage. During the year ended December 31, 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 from equity investments, net in the accompanying consolidated statements of operations. Blackhawk does not have any current activities.

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. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations. On June 5, 2017, the Company contributed all of its membership interests in Stingray Energy to Mammoth Energy. See below under *Mammoth Energy Partners LP/Mammoth Energy Services, Inc.* for information regarding this transaction.

Sturgeon Acquisitions LLC

During 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, 2016, the Company received approximately $1.3 million in distributions from Sturgeon. On June 5, 2017, the Company contributed all of its membership interests in Sturgeon to Mammoth Energy. See below under *Mammoth Energy Partners LP/Mammoth Energy Services, Inc.* for information regarding this transaction.

Mammoth Energy Partners LP/Mammoth Energy Services, Inc.

In the fourth quarter of 2014, the Company contributed its investments in four entities to Mammoth Energy Partners LP ("Mammoth") for a 30.5% interest in this entity. Mammoth originally intended to pursue its initial public offering in 2014 or 2015; however, due to low commodity prices, the offering was postponed. In October 2016, Mammoth converted from a limited partnership into a limited liability company named Mammoth Energy Partners LLC ("Mammoth LLC") and the Company and the other members of Mammoth LLC contributed their interests in Mammoth LLC to Mammoth Energy. The Company received 9,150,000 shares of Mammoth Energy common stock in return for its contribution. Following the contribution, Mammoth Energy completed its initial public offering (the "IPO") of 7,750,000 shares of its common stock at a public offering price of $15.00 per share, of which 7,500,000 shares were sold by Mammoth Energy and 250,000 shares were sold by certain selling stockholders, including 76,250 shares sold by the Company for which it received net proceeds of $1.1 million. At December 31, 2016, the Company owned an approximate 24.2% interest in Mammoth Energy. To reflect the dilution of the Company's shares of Mammoth Energy stock after the IPO, the Company recognized a gain of $3.4 million, which is included in loss from equity method investments, net in the accompanying consolidated statements of operations.

On June 5, 2017, the Company contributed all of its membership interests in Sturgeon (which owns Taylor Frac, LLC, Taylor Real Estate Investments, LLC and South River Road, LLC), Stingray Energy and Stingray Cementing to Mammoth Energy in exchange for approximately 2.0 million shares of Mammoth Energy common stock. As of December 31, 2017, the Company held approximately 25.1% of Mammoth Energy’s outstanding common stock. The Company accounted for the transactions as a sale of financial assets under FASB ASC 860. The Company valued the shares of Mammoth Energy common stock it received in the transactions at $18.50 per share, which was the closing price of Mammoth Energy common stock on June 5, 2017. The Company recognized a gain of $12.5 million from the transactions, which is included in loss from equity method investments, net in the accompanying consolidated statements of operations.

The Company's investment in Mammoth Energy was increased by a $0.2 million foreign currency gain and decreased by a $0.8 million foreign currency loss resulting from Mammoth Energy's foreign subsidiary for the years ended December 31, 2017 and 2016. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

Strike Force Midstream LLC

In February 2016, the Company, through its wholly owned subsidiary Gulfport Midstream Holdings, LLC ("Midstream Holdings"), entered into an agreement 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 through an entity called Strike Force Midstream LLC ("Strike Force"). In 2017, Rice was acquired by EQT Corporation ("EQT"). The Company owns a 25% interest in Strike Force and EQT acts as operator and owns the remaining 75% interest in Strike Force. Construction of the gathering assets, which is ongoing, provides gathering services for wells operated by Gulfport and other operators and connectivity of existing dry gas gathering systems. During the years ended December 31, 2017 and 2016, Gulfport paid $53.0 million and $11.0 million, respectively, in cash calls to Strike Force. For the year ended December 31, 2017, Gulfport received distributions of $6.9 million from Strike Force.

The Company accounted for its initial contribution to Strike Force at fair value under applicable codification guidance. The Company estimated the fair market value of its investment in Strike Force as of the contribution date using the discounted cash flow method under the income approach, based on an independently prepared valuation of the contributed assets. The fair market value was reduced by a discount factor for the lack of marketability due to the Company's minority interest, resulting in a fair value of $22.5 million for the Company's 25% interest. The fair value of the assets contributed was estimated using assumptions that represent Level 3 inputs. See Note 13 - Fair Value Measurements for additional discussion of the measurement inputs. The Company has elected to report its proportionate share of Strike Force's earnings on a one-quarter lag as permitted under FASB ASC 323. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

5. VARIABLE INTEREST ENTITIES

As of December 31, 2017, the Company held variable interests in the following variable interest entities ("VIEs"), but was not the primary beneficiary: Midstream and Timber Wolf. These entities have governing provisions that are the functional equivalent of a limited partnership and are considered VIEs because the limited partners or non-managing members lack substantive kick-out or participating rights which causes the equity owners, as a group, to lack a controlling financial interest. The Company is a limited partner or non-managing member in each of these VIEs and is not the primary beneficiary because it does not have a controlling financial interest. The general partner or managing member has power to direct the activities that most significantly impact the VIEs’ economic performance. The Company also held a variable interest in Strike Force due to the fact that it does not have sufficient equity capital at risk. The Company is not the primary beneficiary of this entity. Prior to Mammoth Energy's IPO, Mammoth LLC was considered a VIE. As a result of the Company’s contribution of its interest in Mammoth LLC to Mammoth Energy in exchange for Mammoth Energy common stock and the completion of Mammoth Energy’s IPO, the Company determined that it no longer held an interest in a VIE. Prior to the contribution of Stingray Energy, Stingray Cementing and Sturgeon to Mammoth Energy, these entities were considered VIEs. As a result of the Company’s contribution of its membership interests in Stingray Energy, Stingray Cementing and Sturgeon to Mammoth Energy in exchange for Mammoth Energy common stock, the Company determined that it no longer held an interest in a VIE.

The Company accounts for its investment in these VIEs following the equity method of accounting. The carrying amounts of the Company’s equity investments are classified as other non-current assets on the accompanying consolidated balance sheets. The Company’s maximum exposure to loss as a result of its involvement with these VIEs is based on the Company’s capital contributions and the economic performance of the VIEs, and is equal to the carrying value of the Company’s investments which is the maximum loss the Company could be required to record in the consolidated statements of operations. See Note 4 for further discussion of these entities, including the carrying amounts of each investment.

6. LONG-TERM DEBT

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

	2017	2016
	(In thousands)	
Revolving credit agreement (1)	$ —	$ —
Building loans (2)	—	—
7.75% senior unsecured notes due 2020 (3)	—	—
6.625% senior unsecured notes due 2023 (4)	350,000	350,000
6.000% senior unsecured notes due 2024 (5)	650,000	650,000
6.375% senior unsecured notes due 2025 (6)	600,000	600,000
6.375% senior unsecured notes due 2026 (7)	450,000	—
Net unamortized original issue premium (discount) (8)	—	—
Net unamortized debt issuance costs (9)	(34,781)	(27,174)
Construction loan (10)	23,724	21,049
Less: current maturities of long term debt	(622)	(276)
Debt reflected as long term	$ 2,038,321	$ 1,593,599

Maturities of long-term debt (excluding unamortized debt issuance costs) as of December 31, 2017 are as follows:

	(In thousands)
2018	$ 622
2019	604
2020	629
2021	661
2022	692
Thereafter	2,070,516
Total	$ 2,073,724

(1) The Company has 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 December 31, 2021. On February 19, 2016, the Company further amended its revolving credit facility to, among other things, (a) increase the basket for unsecured debt issuances to $1.4 billion from $1.2 billion (of which $950 million was then outstanding), (b) reaffirm the Company's borrowing base of $700.0 million, and (c) increase the percentage of projected oil and gas production that may be hedged by the Company during 2016. On December 13, 2016, the Company further amended its revolving credit facility to, among other things, (a) reset the maturity date to December 31, 2021, (b) adjust lenders, (c) increase the basket for unsecured debt issuances to $1.6 billion, (d) increase the interest rates by 50 basis points, (e) increase the mortgage requirement to 85% (from 80%), and (f) add deposit account control agreement language. On March 29, 2017, the Company further amended its revolving credit facility to, among other things, amend the definition of the term EBITDAX to permit pro forma treatment of acquisitions that involve the payment of consideration by Gulfport and its subsidiaries in excess of $50.0 million and of dispositions of property or series of related dispositions of properties that yields gross proceeds to Gulfport or any of its subsidiaries in excess of $50.0 million. On May 4, 2017, the revolving credit facility was further amended to increase the borrowing base from $700.0 million to $1.0 billion, adjust certain of the Company's investment baskets and add five additional banks to the syndicate. On November 21, 2017, the Company further amended its revolving credit facility to, among other things, (a) decrease the applicable rate for all loans by 0.5% and (b) add a provision that allows Gulfport to elect a commitment amount (the "Elected Commitment Amount") that is

less than the borrowing base. In connection with this amendment, the borrowing base was set at $1.2 billion, with an elected commitment of $1.0 billion.

As of December 31, 2017, the Company did not have any outstanding borrowing under the revolving credit facility and the total availability for future borrowings under this facility, after giving effect to an aggregate of $241.0 million of letters of credit, was $759.0 million. The Company's wholly-owned subsidiaries have guaranteed the obligations of the Company under the revolving credit facility.

Advances under the 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 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 revolving credit facility 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;
- 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 revolving credit facility. The revolving credit facility 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, 2017.

(2) In March 2011, the Company entered into a building loan agreement for its former headquarters building in Oklahoma City, Oklahoma. This loan agreement refinanced the $2.4 million outstanding under the previous building loan agreement. The new agreement, as amended in 2014, matured in December 2018 and bore interest at the rate of 4.00% per annum, required monthly interest and principal payments of approximately $20,000 and was collateralized by the Oklahoma City office building and associated land. The Company paid the balance of the loan in full in February 2016.

(3) On October 17, 2012, the Company issued $250.0 million in aggregate principal amount of 7.75% Senior 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 7.75% Senior Notes due 2020 (the "December Notes") as additional securities under the senior note indenture. On August 18, 2014, the Company issued an additional $300.0 million in aggregate principal amount of 7.75% Senior Notes due 2020 (the "August Notes"). The August Notes were issued as additional securities under the senior note indenture. The October Notes, December Notes and the August Notes are collectively referred to as the "2020 Notes."

On October 6, 2016, the Company commenced a cash tender offer to purchase any and all of its 2020 Notes, which tender offer expired on October 13, 2016 and settled on October 14, 2016. Holders of the 2020 Notes that were validly tendered and accepted at or prior to the expiration time of the tender offer, or who delivered the 2020 Notes pursuant to the guaranteed delivery procedures, received total cash consideration of $1,042 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date. An aggregate of $403.5 million in principal amount of the 2020 Notes was validly tendered in the tender offer. The remaining 2020 Notes that were not tendered in the tender offer were redeemed by the Company. The redemption payment included approximately $196.5 million in aggregate principal amount at a redemption price of 103.875% of the principal amount of the redeemed 2020 Notes, plus accrued and unpaid interest thereon to the redemption date. Upon deposit of the redemption payment with the paying agent on October 14, 2016, the indenture governing the 2020 Notes was fully satisfied and discharged. The cash tender offer for the 2020 Notes and redemption of the remaining 2020 Notes were funded with the net proceeds from the offering of the 6.000% Senior Notes due 2024 (the “2024 Notes”) as discussed below and cash on hand.

(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") 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. In October 2015, the 2023 Notes were exchanged for a new issue of substantially identical debt securities registered under the Securities Act. Pursuant to the indenture relating to the 2023 Notes, interest on the 2023 Notes accrues at a rate of 6.625% per annum on the outstanding principal amount thereof, payable semi-annually on May 1 and November 1 of each year. 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) On October 14, 2016, the Company issued the 2024 Notes in aggregate principal amount of $650.0 million. The 2024 Notes were issued under an indenture, dated as of October 14, 2016, among the Company, the subsidiary guarantors party thereto and the senior note indenture trustee (the "2024 Indenture"), 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 “2024 Notes Offering”). Under the 2024 Indenture, interest on the 2024 Notes accrues at a rate of 6.000% per annum on the outstanding principal amount thereof from October 14, 2016, payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2017. The 2024 Notes will mature on October 15, 2024. The Company received approximately $638.9 million in net proceeds from the offering of the 2024 Notes, which was used, together with cash on hand, to purchase the outstanding 2020 Notes in a concurrent cash tender offer, to pay fees and expenses thereof, and to redeem any of the 2020 Notes that remained outstanding after the completion of the tender offer.

(6) On December 21, 2016, the Company issued $600.0 million in aggregate principal amount of 6.375% Senior Notes due 2025 (the “2025 Notes”). The 2025 Notes were issued under an indenture, dated as of December 21, 2016, among the Company, the subsidiary guarantors party thereto and the senior note indenture trustee (the "2025 Indenture"), to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. Under the 2025 Indenture, interest on the 2025 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from December 21, 2016, payable semi-annually on May 15 and November 15 of each year, commencing on May 15, 2017. The 2025 Notes will mature on May 15, 2025. The Company received approximately $584.7 million in net proceeds from the offering of the 2025 Notes, which was used, together with the net proceeds from the Company's December 2016 common stock offering and cash on hand, to fund the cash portion of the purchase price for the Vitruvian Acquisition. See Note 2 for additional discussion of the Vitruvian Acquisition.

In connection with each of the 2024 and 2025 Notes Offering, the Company and its subsidiary guarantors entered into a registration rights agreement pursuant to which the Company agreed to file a registration statement with respect to offers to exchange the 2024 Notes and 2025 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offers for the 2024 Notes and 2025 Notes were completed on September 12, 2017.

(7) On October 11, 2017, the Company issued $450.0 million in aggregate principal amount of its 6.375% Senior Notes due 2026 (the “2026 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. Interest on the 2026 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from October 11, 2017, payable semi-annually on January 15 and July 15 of each year, commencing on January 15, 2018. The 2026 Notes will mature on January 15, 2026. The Company received approximately $444.3 million in net proceeds from the offering of the 2026 Notes, a portion of which was used to repay all of the Company's outstanding borrowings under its secured revolving credit facility on October 11, 2017 and the balance was used to fund the remaining outspend related to the Company's 2017 capital development plans.

In connection with the 2026 Notes offering, the Company and its subsidiary guarantors entered into a registration rights agreement pursuant to which the Company agreed to file a registration statement with respect to an offer to exchange the 2026 Notes for a new issue of substantially identical debt securities registered under the Securities Act. On January 18, 2018, the Company filed a registration statement on Form S-4 with respect to an offer to exchange the 2026 Notes for substantially identical debt securities registered under the Securities Act, which registration statement was declared effective by the SEC on February 12, 2018. The Company commenced the exchange offer relating to the 2026 notes on February 16, 2018, which it expects to close in March of 2018.

(8) 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 2023 Notes, 2024 Notes, 2025 Notes and 2026 Notes were issued at par. The premium and discount was amortized using the effective interest method until the bonds were redeemed, at which point the remaining premium and discount of $10.8 million was written off and is included in loss on debt extinguishment on the consolidated statements of operations.

(9) In accordance with ASU 2015-03, loan issuance cost related to the 2023 Notes, the 2024 Notes, the 2025 Notes and the 2026 Notes (collectively the "Notes") have been presented as a reduction to the Notes. At December 31, 2017, total unamortized debt issuance costs were $5.2 million for the 2023 Notes, $9.9 million for the 2024 Notes, $14.0 million for the 2025 Notes and $5.5 million for the 2026 Notes. In addition, loan commitment fee costs for the construction loan agreement described immediately below were $0.1 million at December 31, 2017.

(10) 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, which was substantially completed in December 2016. The Construction Loan allows for maximum principal borrowings of $24.5 million and required the Company to fund 30% of the cost of the construction before any funds could 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 was payable on the last day of the month through May 31, 2017. Starting June 30, 2017, the Company began making monthly payments of principal and interest, with the final payment due June 4, 2025. At December 31, 2017, the total borrowings under the Construction loan were approximately $23.7 million.

Interest Expense

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

	2017	2016	2015
		(In thousands)	
Cash paid for interest	$ 101,958	$ 68,966	$ 59,736
Change in accrued interest	10,699	1,768	4,011
Capitalized interest	(9,470)	(9,148)	(13,580)
Amortization of loan costs	5,011	3,660	3,219
Amortization of note discount and premium	—	(1,716)	(2,165)
Total interest expense	$ 108,198	$ 63,530	$ 51,221

The Company capitalized approximately $9.5 million and $8.7 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2017 and 2016, respectively. During the year ended December 31, 2016, the Company also capitalized approximately $0.4 million in interest expense related to building construction. Construction on the building was completed in December 2016 and, as such, the Company did not capitalize any interest expense related to building construction for the year ended December 31, 2017.

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, 2017, 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.

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 2005 Plan. The shares of stock issued once the options are exercised will be from authorized but unissued common stock. As of December 31, 2017, the Company had granted 1,939,053 shares of restricted stock under the 2013 Plan.

Issuance of Common Stock

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 Partners III, LLC 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 purchase of acreage in Monroe County, Ohio and used the remaining funds for general corporate purposes, including the funding of a portion of its 2015 capital development plans.

On March 15, 2016, the Company issued 16,905,000 shares of its common stock in an underwritten public offering (which included 2,205,000 shares sold pursuant to an option to purchase additional shares of the Company's common stock granted by the Company to, and exercised in full by, the underwriters). The net proceeds from this equity offering were approximately $411.7 million, after underwriting discounts and commissions and offering expenses. The Company used the net proceeds from this offering primarily to fund a portion of its 2017 capital development plan and for general corporate purposes.

On December 21, 2016, the Company issued an aggregate 33,350,000 shares of its common stock in an underwritten public offering (which included 4,350,000 shares subject to an option to purchase additional shares exercised by the underwriters). The net proceeds from this equity offering were approximately $698.8 million, after deducting underwriting discounts and commissions and estimated offering expenses. The Company used the net proceeds from this offering, together with the net proceeds from the offering of the 2025 Notes and cash on hand, to fund the cash portion of the purchase price for the Vitruvian Acquisition (see Note 2).

On February 17, 2017, the Company completed the Vitruvian Acquisition for a total initial purchase price of approximately $1.85 billion, consisting of $1.35 billion in cash, subject to certain adjustments, and approximately 23.9 million shares of the Company's common stock (of which approximately 5.2 million shares are subject to the indemnity escrow). See Note 2 for additional discussion of the Vitruvian Acquisition.

8. STOCK-BASED COMPENSATION

During the years ended December 31, 2017, 2016 and 2015 the Company's stock-based compensation cost was $10.6 million, $12.3 million and $14.4 million, respectively, of which the Company capitalized $4.2 million, $4.9 million and $5.7 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, 2017, 2016 and 2015.

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, 2017, 2016 and 2015 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, 2015	5,000	$ 9.07	0.69	$ 163
Granted	—	—		
Exercised	(5,000)	9.07		124
Forfeited/expired	—	—		
Options outstanding at December 31, 2015	—	—	—	$ —
Granted	—	—		
Exercised	—	—		—
Forfeited/expired	—	—		
Options outstanding at December 31, 2016	—	—	—	$ —
Granted	—	—		
Exercised	—	—		—
Forfeited/expired	—	—		
Options outstanding at December 31, 2017	—	$ —	—	$ —
Options exercisable at December 31, 2017	—	$ —	—	$ —

The following table summarizes restricted stock activity for the twelve months ended December 31, 2017, 2016 and 2015:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of January 1, 2015	387,245	$ 55.87
Granted	352,605	35.99
Vested	(236,812)	52.39
Forfeited	(18,799)	45.21
Unvested shares as of December 31, 2015	484,239	$ 43.51
Granted	451,241	$ 27.78
Vested	(252,566)	43.94
Forfeited	(69,858)	33.43
Unvested shares as of December 31, 2016	613,056	$ 32.90
Granted	876,846	$ 15.14
Vested	(423,977)	29.90
Forfeited	(89,898)	27.91
Unvested shares as of December 31, 2017	976,027	$ 18.71

Unrecognized compensation expense as of December 31, 2017 related to outstanding stock options and restricted shares was $14.4 million. The expense is expected to be recognized over a weighted average period of 1.46 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, 2017, the carrying value of the outstanding debt represented by the Notes was $ 2.0 billion including the unamortized debt issuance cost of approximately $5.2 million related to the 2023 Notes, approximately $9.9 million related to the 2024 Notes, approximately $14.0 million related to the 2025 Notes, and approximately $5.5 million related to the 2026 Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $2.1 billion at December 31, 2017.

10. INCOME TAXES

The income tax provision consists of the following:

	2017	2016	2015
		(In thousands)	
Current:			
State	$ 2,167	$ (1,330)	$ (1,069)
Federal	3,362	(19,770)	(439)
Deferred:			
State	(118)	(386)	(14,218)
Federal	(3,602)	18,573	(240,275)
Total income tax expense (benefit) provision	$ 1,809	$ (2,913)	$ (256,001)

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

	2017	2016	2015
		(In thousands)	
Income (loss) before federal income taxes	$ 436,961	$ (982,622)	$ (1,480,885)
Expected income tax at statutory rate	152,936	(343,918)	(518,310)
State income taxes	2,299	(5,883)	(15,908)
Other differences	5,731	4,293	(420)
Intraperiod tax allocation	—	(1,349)	—
Remeasurement due to Tax Cut and Jobs Act	190,034	—	—
Change in valuation allowance due to current year activity	(158,704)	343,944	278,637
Change in valuation allowance due to Tax Cuts and Jobs Act	(190,487)	—	—
Income tax expense (benefit) recorded	$ 1,809	$ (2,913)	$ (256,001)

The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2017, 2016 and 2015 are estimated as follows:

	2017	2016	2015
		(In thousands)	
Deferred tax assets:			
Net operating loss carryforward	$ 120,626	$ 162,073	$ 46,209
Oil and gas property basis difference	151,260	386,302	292,838
Investment in pass through entities	12,343	27,469	14,034
FASB ASC 718 compensation expense	813	2,084	1,922
Business energy investment tax credit	369	369	—
AMT credit	—	3,842	23,629
Charitable contributions carryover	255	303	146
Unrealized loss on hedging activities	—	48,317	—
Foreign tax credit carryforwards	2,074	2,074	2,074
Accrued liabilities	285	397	—
ARO liability	15,897	12,107	9,415
Non-oil and gas property basis difference	171	—	—
State net operating loss carryover	6,954	5,351	4,344
Total deferred tax assets	311,047	650,688	394,611
Valuation allowance for deferred tax assets	(298,830)	(645,841)	(303,246)
Deferred tax assets, net of valuation allowance	12,217	4,847	91,365
Deferred tax liabilities:			
Non-oil and gas property basis difference	—	155	715
Unrealized gain on hedging activities	11,009	—	66,422
Total deferred tax liabilities	11,009	155	67,137
Net deferred tax asset	$ 1,208	$ 4,692	$ 24,228

The Company has an available federal tax net operating loss carryforward estimated at approximately $574.4 million as of December 31, 2017. This carryforward will begin to expire in the year 2023. Based upon the December 31, 2017 net deferred tax asset position and a recent history of cumulative losses, 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 $121.3 million that began to expire in 2017 and federal foreign tax credit carryovers of $2.1 million which began to expire in 2017. The Company believes that it can utilize an Oklahoma state NOL through carrybacks. Therefore, the Company has recorded a total valuation allowance of $298.8 million related to the remaining net deferred tax asset.

The Tax Act was enacted on December 22, 2017. The Tax Act reduces the US federal corporate tax rate from 35% to 21% effective January 1, 2018. Deferred tax assets and liabilities are measured using the enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. As a result of the reduction in the statutory rate, the Company has remeasured its deferred tax balances, the effects of which are reflected in the rate reconciliation shown in the table above. The Company has applied the provisions of SEC Staff Accounting Bulletin No. 118 ("SAB 118"). SAB 118 allows for a measurement period in which companies can either use provisional estimates for changes resulting from the Tax Act or apply the tax laws that were in effect immediately prior to the Tax Act being enacted if estimates cannot be determined at the time of the preparation of the financial statements until the actual impacts can be determined. The Company has recorded a provisional estimate of $0.5 million benefit for the impact of the Tax Act within its December 31, 2017 financial statements. The Company will continue to evaluate the impacts of the Tax Act on deferred taxes, compensation and international provisions and will record adjustments, as needed, based on changes to its estimates.

The Company's income tax benefit in 2016 and 2015 was primarily attributable to the Company recording a full cost ceiling impairment of $715.5 million and $1.4 billion against the oil and gas assets. The Company's income tax expense in 2017 is primarily the result of a change in state income tax positions.

As of December 31, 2017, the amount of unrecognized tax benefits related to federal and state tax liabilities associated with uncertain tax positions was immaterial.

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,								
	2017			2016			2015		
	Income	Shares	Per Share	Loss	Shares	Per Share	Loss	Shares	Per Share
	(In thousands, except share data)								
Basic:									
Net income (loss)	$435,152	179,834,146	$ 2.42	$(979,709)	122,952,866	$ (7.97)	$(1,224,884)	99,792,401	$(12.27)
Effect of dilutive securities:									
Stock options and awards	—	418,878		—	—		—	—	
Diluted:									
Net income (loss)	$435,152	180,253,024	$ 2.41	$(979,709)	122,952,866	$ (7.97)	$(1,224,884)	99,792,401	$(12.27)

There were no potential shares of common stock that were considered anti-dilutive for the year ended December 31, 2017. There were 539,988 and 449,880 shares of common stock that were considered anti-dilutive for the years ended 2016 and 2015, respectively.

12. DERIVATIVE INSTRUMENTS

Natural Gas, Oil and Natural Gas Liquids Derivative Instruments

The Company seeks to reduce its exposure to unfavorable changes in natural gas, oil 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 the NYMEX Henry Hub for natural gas, Argus Louisiana Light Sweet Crude for oil, the NYMEX West Texas Intermediate for oil, and Mont Belvieu for propane and pentane. Below is a summary of the Company's open fixed price swap positions as of December 31, 2017.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
2018	NYMEX Henry Hub	908,000	$ 3.06
2019	NYMEX Henry Hub	269,000	$ 2.93

	Location	Daily Volume (Bbls/day)	Weighted Average Price
2018	ARGUS LLS	1,500	$ 56.22
2018	NYMEX WTI	4,000	$ 52.20

	Location	Daily Volume (Bbls/day)	Weighted Average Price
2018	Mont Belvieu C3	3,500	$ 28.03
2018	Mont Belvieu C5	500	$ 46.62

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.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
January 2018 - March 2018	NYMEX Henry Hub	20,000	$ 2.91
April 2018 - March 2019	NYMEX Henry Hub	50,000	$ 3.13
April 2019 - December 2019	NYMEX Henry Hub	30,000	$ 3.10

For a portion of the natural gas fixed price swaps listed above, the counterparty has an option to extend the original terms an additional twelve months for the period January 2019 through December 2019. The option to extend the terms expires in December 2018. If executed, the Company would have additional fixed price swaps for 100,000 MMBtu per day at a weighted average price of $3.05 per MMBtu.

In addition, the Company has entered into natural gas basis swap positions, which settle on the pricing index to basis differential of NPGL Mid-Continent to NYMEX Henry Hub. As of December 31, 2017, the Company had the following natural gas basis swap positions for NPGL Mid-Continent.

	Location	Daily Volume (MMBtu/day)	Hedged Differential
2018	NPGL Mid-Continent	12,000	$ (0.26)

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, 2017 and 2016:

	December 31,	
	2017	2016
	(In thousands)	
Short-term derivative instruments - asset	$ 78,847	$ 3,488
Long-term derivative instruments - asset	$ 8,685	$ 5,696
Short-term derivative instruments - liability	$ 32,534	$ 119,219
Long-term derivative instruments - liability	$ 2,989	$ 26,759

Gains and losses

The following table presents the gain and loss recognized in net gain (loss) on natural gas, oil and NGL derivatives in the accompanying consolidated statements of operations for the years ended December 31, 2017, 2016, and 2015.

	Gain (loss) on derivative instruments		
	For the Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Natural gas derivatives	$ 232,143	$ (165,933)	$ 182,993
Oil derivatives	(3,350)	(5,387)	19,201
Natural gas liquids derivatives	(15,114)	(3,186)	1,319
Total	$ 213,679	$ (174,506)	$ 203,513

The Company delivered approximately 68% of its 2017 production under fixed price swaps.

Offsetting of derivative assets and liabilities

As noted above, the Company records the fair value of derivative instruments on a gross basis. The following table presents the gross amounts of recognized derivative assets and liabilities in the consolidated balance sheets and the amounts that are subject to offsetting under master netting arrangements with counterparties, all at fair value.

	As of December 31, 2017		
	Derivative instruments, gross	Netting adjustments	Derivative instruments, net
	(In thousands)		
Derivative assets	$ 87,532	$ (22,199)	$ 65,333
Derivative liabilities	$ (35,523)	$ 22,199	$ (13,324)

	As of December 31, 2016		
	Derivative instruments, gross	Netting adjustments	Derivative instruments, net
	(In thousands)		
Derivative assets	$ 9,184	$ (9,184)	$ —
Derivative liabilities	$ (145,978)	$ 9,184	$ (136,794)

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. None of the Company's derivative instrument contracts contain credit-risk related contingent features. 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, 2017 and 2016:

	December 31, 2017		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$ —	$ 87,532	$ —
Liabilities:			
Derivative Instruments	$ —	$ 35,523	$ —

	December 31, 2016		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$ —	$ 9,184	$ —
Liabilities:			
Derivative Instruments	$ —	$ 145,978	$ —

The Company estimates the fair value of all derivative instruments using 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. The asset retirement obligations assumed as part of the business combination were estimated using the same assumptions and methodology as described below. 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 or revised during the year ended December 31, 2017 were approximately $16.3 million and $26.0 million, respectively.

The fair value of the common stock received from Mammoth Energy in connection with the Company's contribution of all of its membership interests in Sturgeon, Stingray Energy and Stingray Cementing was estimated using Level 1 inputs, as the price per share was a quoted price in an active market for identical Mammoth Energy common shares.

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 March 31, 2016 to be approximately $39.1 million. See Note 4 for further discussion of the Company's investment in Grizzly.

Due to the unobservable nature of the inputs, the fair value of the Company's investment in Strike Force was estimated using assumptions that represent Level 3 inputs. The Company's estimated fair value of the investment as of the February 1, 2016 contribution date was $22.5 million. See Note 4 for further discussion of the Company's contribution to Strike Force.

14. RELATED PARTY TRANSACTIONS

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

Stingray Cementing provides well cementing services. Stingray Cementing was previously 50% owned by the Company until its contribution to Mammoth Energy in June 2017 as discussed above in Note 4. At the date of the contribution, the Company owed Stingray Cementing approximately $0.5 million. As of December 31, 2016, the Company owed Stingray Cementing approximately $0.5 million related to these services.

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. Stingray Energy was previously 50% owned by the Company until its contribution to Mammoth Energy in June 2017 as discussed above in Note 4. At the date of the contribution, the Company owed Stingray

Energy approximately $1.6 million. As of December 31, 2016, the Company owed Stingray Energy approximately $3.6 million related to these services.

As of December 31, 2017, the Company held approximately 25.1% of Mammoth Energy's outstanding common stock as discussed above in Note 4. Approximately $2.1 million of services provided by Mammoth Energy are included in lease operating expenses in the consolidated statements of operations for the year ended December 31, 2017. Approximately $196.5 million and $110.5 million of services provided by Mammoth Energy are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2017 and 2016, respectively. At December 31, 2017 and 2016, the Company owed Mammoth Energy approximately $32.0 million and $23.5 million, respectively, related to these services.

Strike Force, which is 25% owned by the Company, develops natural gas gathering assets in dedicated areas as discussed above in Note 4. At December 31, 2017 and 2016 the Company owed approximately $8.4 million and $1.6 million, respectively, to Strike Force for these related services. Approximately $23.1 million and $1.8 million of services provided by Strike Force are included in midstream gathering and processing on the accompanying consolidated statement of operations for the years ended December 31, 2017 and 2016, respectively.

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, 2017, the plugging and abandonment trust totaled approximately $3.1 million. At December 31, 2017, the Company had plugged 551 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 bi-weekly contribution 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, 2017, 2016 and 2015, Gulfport incurred $3.0 million, $1.7 million, and $1.4 million, respectively, in contributions expense related to this plan.

Employment Agreements

On April 22, 2014, the Board of Directors appointed Michael G. Moore as Chief Executive Officer of the Company. The Company and Mr. Moore entered into an amended and restated employment agreement. The agreement has a three-year term commencing effective April 22, 2014, which was amended effective as of April 29, 2015. The employment agreement, as amended and restated as of April 29, 2015, 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 Ross Kirtley, the Company's Chief Operating Officer. The agreement had a two-year term commencing effective April 22, 2014. This agreement provided, 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 August 5, 2016, Mr. Kirtley's employment as the Company's Chief Operating Officer terminated.

In connection with Mr. Kirtley's termination, the Company entered into a separation and release agreement with Mr. Kirtley, dated as of November 2, 2016 (the "Separation Agreement"), pursuant to which the Company agreed to provide Mr. Kirtley with (i) the cash compensation specified in his employment agreement, (ii) health care benefits for Mr. Kirtley and his eligible dependents for up to eighteen (18) months following the termination date, (iii) his company vehicle, (iv) the vesting of

3,000 shares of restricted stock and (v) the vesting of 14,820 restricted stock units provided that such restricted stock units will be settled in four substantially equal annual installments beginning in March 2017 in accordance with the original vesting schedule. All other restricted stock and restricted stock unit awards granted to Mr. Kirtley were forfeited and terminated.

Under the Separation Agreement, Mr. Kirtley is subject to certain covenants regarding confidentiality, non-solicitation, non-competition, trade secrets, unfair competition and inventions. The Separation Agreement also contains customary waiver and release provisions pursuant to which Mr. Kirtley waived, released and discharged the Company and certain other related parties from any and all claims that Mr. Kirtley may have had against the Company or such other parties as of the date of the Separation Agreement.

On March 13, 2015, the Company entered into an employment agreement with Aaron Gaydosik, the Company's Chief Financial Officer. The agreement had a three-year term commencing effective August 11, 2014. This agreement provided, 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. Mr. Gaydosik's employment agreement was terminated upon his resignation as the Company's Chief Financial Officer, effective January 4, 2017. As provided in such employment agreement, upon resignation, Mr. Gaydosik was entitled to any of his earned but unpaid salary through the date of resignation. Any unvested awards granted to Mr. Gaydosik under the Company's equity incentive plan lapsed.

The Company has also entered into employment agreements with certain members of management that provide for one-year terms commencing as of January 1, 2017 (the "Initial Period"), which automatically extend for successive one-year periods unless the Company or the executive elects to not extend the term by giving written notice to the other party at least 30 days' prior to the end of the Initial Period or any anniversary thereof. The agreements provide for, among other things, compensation, benefits and severance payments. The employment agreements also contains certain termination and change of control provisions.

Firm Transportation Commitments

The Company had approximately 2,629,800 MMBtu per day of firm sales contracted with third parties. The table below presents these commitments at December 31, 2017 as follows:

	(MMBtu per day)
2018	560,800
2019	659,000
2020	526,000
2021	372,000
2022	272,000
Thereafter	240,000
Total	2,629,800

The Company also had approximately $3.8 billion of firm transportation contracted with third parties. The table below presents these commitments at December 31, 2017 as follows:

	(In thousands)
2018	$ 248,047
2019	251,644
2020	247,581
2021	246,620
2022	246,620
Thereafter	2,511,853
Total	$ 3,752,365

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, 2017 are as follows:

		(In thousands)
2018	$	136
2019		54
Total	$	190

Presented below is rent expense for the years ended December 31, 2017, 2016 and 2015, respectively.

	For the years ended December 31,					
	2017		2016		2015	
	(In thousands)					
Minimum rentals	$	343	$	840	$	759
Less: Sublease rentals		—		—		8
	$	343	$	840	$	751

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. The Company incurred $1.9 million related to non-utilization fees during the year ended 2016. The Company did not incur any non-utilization fees during the year ended December 31, 2017.

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, 2017 are as follows:

		(In thousands)
2018	$	39,330
Total	$	39,330

16. CONTINGENCIES

In two separate complaints, one filed by the State of Louisiana and the Parish of Cameron in the 38th Judicial District Court for the Parish of Cameron on February 9, 2016 and the other filed by the State of Louisiana and the District Attorney for the 15th Judicial District of the State of Louisiana in the 15th Judicial District Court for the Parish of Vermilion on July 29, 2016, the Company was named as a defendant, among 26 oil and gas companies, in the Cameron Parish complaint and among more than 40 oil and gas companies in the Vermilion Parish complaint, or the Complaints. The Complaints were filed under the State and Local Coastal Resources Management Act of 1978, as amended, and the rules, regulations, orders and ordinances adopted thereunder, which the Company referred to collectively as the CZM Laws, and allege that certain of the defendants' oil and gas exploration, production and transportation operations associated with the development of the East Hackberry and West Hackberry oil and gas fields, in the case of the Cameron Parish complaint, and the Tigre Lagoon and Lac Blanc oil and gas fields, in the case of the Vermilion Parish complaint, were conducted in violation of the CZM Laws. The Complaints allege that such activities caused substantial damage to land and waterbodies located in the coastal zone of the relevant Parish, including due to defendants' design, construction and use of waste pits and the alleged failure to properly close the waste pits and to clear, re-vegetate, detoxify and return the property affected to its original condition, as well as the defendants' alleged discharge of waste into the coastal zone. The Complaints also allege that the defendants' oil and gas activities have resulted in the dredging of numerous canals, which had a direct and significant impact on the state coastal waters within the relevant Parish and that the defendants, among other things, failed to design, construct and maintain these canals using the best practical techniques to prevent bank slumping, erosion and saltwater intrusion and to minimize the potential for inland movement of storm-generated surges, which activities allegedly have resulted in the erosion of marshes and the degradation of terrestrial and aquatic life therein. The Complaints also allege that the defendants failed to re-vegetate, refill, clean, detoxify and otherwise restore these canals to their original condition. In these two petitions, the plaintiffs seek damages and other appropriate relief under the CZM Laws, including the payment of costs necessary to clear, re-vegetate, detoxify and otherwise restore the affected coastal zone of the relevant Parish to its original condition, actual restoration of such coastal zone to its original condition, and the payment of reasonable attorney fees and legal expenses and pre-judgment and post judgment interest.

The Company was served with the Cameron complaint in early May 2016 and with the Vermilion Complaint in early September 2016. The Louisiana Attorney General and the Louisiana Department of Natural Resources intervened in both the Cameron Parish suit and the Vermilion Parish suit. Shortly after the Complaints were filed, certain defendants removed the cases to the lawsuit to the United States District Court for the Western District of Louisiana. In both cases, the plaintiffs filed a motion to remand, and the plaintiffs agreed to an extension of time for all defendants to file responsive pleadings until the District Courts ruled on the motions to remand. In the Vermilion Parish case, the District Court entered an order on September 26, 2017 remanding the lawsuit to the 15th Judicial District Court, State of Louisiana, Parish of Vermilion. In the Cameron Parish lawsuit, the federal magistrate, on January 18, 2018, issued a report and recommendation that the Cameron Parish lawsuit be remanded to the 38th Judicial District Court, State of Louisiana, Parish of Cameron. It is anticipated that one or more of the defendants will object to the magistrate's report and recommendation, in which case the report and recommendation will be reviewed by the District Court after additional briefing by the parties. Due to the procedural posture of lawsuits, the fact that responsive pleadings have not been filed and the fact that the parties have not begun discovery and the Company has not had the opportunity to evaluate the applicability of the allegations made in plaintiffs' complaints to the Company's operations, management cannot determine the amount of loss, if any, that may result.

In addition, 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

For the years ended December 31, 2016 and 2015 the Company was reimbursed $5.7 million and $10.0 million, respectively, net of related legal fees by its insurance provider, which is included in insurance proceeds in the accompanying consolidated statements of operations.

Concentration of Credit Risk

Gulfport operates in the oil and natural gas industry principally in the states of Ohio, Oklahoma and Louisiana with sales to refineries, re-sellers such as marketers, and other end users. 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, 2017, Gulfport held cash in excess of insured limits in these banks totaling $97.6 million.

The Company's sales to major customers (purchases of 10% or more of total sales before the effects of hedging) for the years ended December 31, 2017, 2016 and 2015 are as follows:

	December 31,		
	2017	2016	2015
Company A	40 %	59 %	62 %
Company B	5 %	12 %	23 %
Company C	7 %	10 %	12 %
All others	48 %	19 %	3 %

17. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On October 17, 2012, December 21, 2012 and August 18, 2014, the Company issued the 2020 Notes in an aggregate of $600.0 million principal amount. The 2020 Notes were subsequently exchanged for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act. In October 2016, the Company repurchased (in a cash tender offer) or redeemed all of the 2020 Notes, of which $600.0 million in aggregate principal amount was then outstanding, with the net proceeds from the issuance of the 2024 Notes discussed below and cash on hand.

On April 21, 2015, the Company issued $350.0 million in aggregate principal amount of the 2023 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. 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.

On October 14, 2016, the Company issued $650.0 million in aggregate principal amount of the 2024 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 net proceeds from the issuance of the 2024 Notes, together with cash on hand, were used to repurchase or redeem all of the then-outstanding 2020 Notes in October 2016.

On December 21, 2016, the Company issued $600.0 million in aggregate principal amount of the 2025 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 Company used the net proceeds from the issuance of the 2025 Notes, together with the net proceeds from the December 2016 underwritten offering of the Company’s common stock and cash on hand, to fund the cash portion of the purchase price for the Vitruvian Acquisition.

In connection with the 2024 Notes Offering and the 2025 Notes Offering, the Company and its subsidiary guarantors entered into two registration rights agreements, pursuant to which the Company agreed to file a registration statement with respect to offers to exchange the 2024 Notes and the 2025 Notes for new issues of substantially identical debt securities registered under the Securities Act. The exchange offers for the 2024 Notes and the 2025 Notes were completed on September 13, 2017.

On October 11, 2017, the Company issued $450.0 million in aggregate principal amount of the 2026 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. A portion of the net proceeds from the issuance of the 2026 Notes was used to repay all of the Company's outstanding borrowings under its secured revolving credit facility on October 11, 2017 and the balance was used to fund the remaining outspend related to the Company's 2017 capital development plans.

The 2020 Notes were, and the 2023 Notes, the 2024 Notes, the 2025 Notes and the 2026 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 were not, and the 2023 Notes, the 2024 Notes, the 2025 Notes and the 2026 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.

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, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 67,908	$ 31,649	$ —	$ —	$ 99,557
Restricted cash	—	—	—	—	—
Accounts receivable - oil and natural gas	128,121	54,092	—	—	182,213
Accounts receivable - related parties	—	—	—	—	—
Accounts receivable - intercompany	554,439	63,374	—	(617,813)	—
Prepaid expenses and other current assets	4,719	193	—	—	4,912
Short-term derivative instruments	78,847	—	—	—	78,847
Total current assets	834,034	149,308	—	(617,813)	365,529
Property and equipment:					
Oil and natural gas properties, full-cost accounting	6,562,147	2,607,738	—	(729)	9,169,156
Other property and equipment	86,711	43	—	—	86,754
Accumulated depletion, depreciation, amortization and impairment	(4,153,696)	(37)	—	—	(4,153,733)
Property and equipment, net	2,495,162	2,607,744	—	(729)	5,102,177
Other assets:					
Equity investments and investments in subsidiaries	2,361,575	77,744	57,641	(2,194,848)	302,112
Long-term derivative instruments	8,685	—	—	—	8,685
Deferred tax asset	1,208	—	—	—	1,208
Inventories	5,816	2,411	—	—	8,227
Other assets	12,483	7,331	—	—	19,814
Total other assets	2,389,767	87,486	57,641	(2,194,848)	340,046
Total assets	$ 5,718,963	$ 2,844,538	$ 57,641	$ (2,813,390)	$ 5,807,752
Liabilities and stockholders' equity					
Current liabilities:					
Accounts payable and accrued liabilities	$ 416,249	$ 137,361	$ —	$ (1)	$ 553,609
Accounts payable - intercompany	63,373	554,313	127	(617,813)	—
Asset retirement obligation - current	120	—	—	—	120
Short-term derivative instruments	32,534	—	—	—	32,534
Current maturities of long-term debt	622	—	—	—	622
Total current liabilities	512,898	691,674	127	(617,814)	586,885
Long-term derivative instruments	2,989	—	—	—	2,989
Asset retirement obligation - long-term	63,141	11,839	—	—	74,980
Other non-current liabilities	—	2,963	—	—	2,963
Long-term debt, net of current maturities	2,038,321	—	—	—	2,038,321
Total liabilities	2,617,349	706,476	127	(617,814)	2,706,138
Stockholders' equity:					
Common stock	1,831	—	—	—	1,831
Paid-in capital	4,416,250	1,915,598	259,307	(2,174,905)	4,416,250
Accumulated other comprehensive (loss) income	(40,539)	—	(38,593)	38,593	(40,539)
Retained (deficit) earnings	(1,275,928)	222,464	(163,200)	(59,264)	(1,275,928)
Total stockholders' equity	3,101,614	2,138,062	57,514	(2,195,576)	3,101,614
Total liabilities and stockholders' equity	$ 5,718,963	$ 2,844,538	$ 57,641	$ (2,813,390)	$ 5,807,752

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets					
Cash and cash equivalents	$ 1,273,882	$ 1,993	$ —	$ —	$ 1,275,875
Restricted cash	185,000	—	—	—	$ 185,000
Accounts receivable - oil and natural gas	137,087	37,496	—	(37,822)	136,761
Accounts receivable - related parties	16	—	—	—	16
Accounts receivable - intercompany	449,517	1,151	—	(450,668)	—
Prepaid expenses and other current assets	3,135	—	—	—	3,135
Short-term derivative instruments	3,488	—	—	—	3,488
Total current assets	2,052,125	40,640	—	(488,490)	1,604,275
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	5,655,125	417,524	—	(729)	6,071,920
Other property and equipment	68,943	43	—	—	68,986
Accumulated depletion, depreciation, amortization and impairment	(3,789,746)	(34)	—	—	(3,789,780)
Property and equipment, net	1,934,322	417,533	—	(729)	2,351,126
Other assets:					
Equity investments and investments in subsidiaries	236,327	33,590	45,213	(71,210)	243,920
Long-term derivative instruments	5,696	—	—	—	5,696
Deferred tax asset	4,692	—	—	—	4,692
Inventories	3,095	1,409	—	—	4,504
Other assets	8,932	—	—	—	8,932
Total other assets	258,742	34,999	45,213	(71,210)	267,744
Total assets	$ 4,245,189	$ 493,172	$ 45,213	$ (560,429)	$ 4,223,145
Liabilities and stockholders' equity					
Current liabilities:					
Accounts payable and accrued liabilities	$ 255,966	$ 9,158	$ —	$ —	$ 265,124
Accounts payable - intercompany	31,202	457,163	126	(488,491)	—
Asset retirement obligation - current	195	—	—	—	195
Short-term derivative instruments	119,219	—	—	—	119,219
Current maturities of long-term debt	276	—	—	—	276
Total current liabilities	406,858	466,321	126	(488,491)	384,814
Long-term derivative instruments	26,759	—	—	—	26,759
Asset retirement obligation - long-term	34,081	—	—	—	34,081
Long-term debt, net of current maturities	1,593,599	—	—	—	1,593,599
Total liabilities	2,061,297	466,321	126	(488,491)	2,039,253
Stockholders' equity:					
Common stock	1,588	—	—	—	1,588
Paid-in capital	3,946,442	33,822	257,026	(290,848)	3,946,442
Accumulated other comprehensive (loss) income	(53,058)	—	(50,931)	50,931	(53,058)
Retained (deficit) earnings	(1,711,080)	(6,971)	(161,008)	167,979	(1,711,080)
Total stockholders' equity	2,183,892	26,851	45,087	(71,938)	2,183,892
Total liabilities and stockholders' equity	$ 4,245,189	$ 493,172	$ 45,213	$ (560,429)	$ 4,223,145

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 1,010,989	$ 309,314	$ —	$ —	$ 1,320,303
Costs and expenses:					
Lease operating expenses	65,793	14,453	—	—	80,246
Production taxes	15,100	6,026	—	—	21,126
Midstream gathering and processing	187,678	61,317	—	—	248,995
Depreciation, depletion and amortization	364,625	4	—	—	364,629
General and administrative	55,589	(2,654)	3	—	52,938
Accretion expense	1,246	365	—	—	1,611
Acquisition expense	—	2,392	—	—	2,392
	690,031	81,903	3	—	771,937
INCOME (LOSS) FROM OPERATIONS	320,958	227,411	(3)	—	548,366
OTHER (INCOME) EXPENSE:					
Interest expense	112,732	(4,534)	—	—	108,198
Interest income	(988)	(21)	—	—	(1,009)
(Income) loss from equity method investments and investments in subsidiaries	(226,130)	1,955	2,189	227,243	5,257
Other (income) expense	(1,617)	(324)	—	900	(1,041)
	(116,003)	(2,924)	2,189	228,143	111,405
INCOME (LOSS) BEFORE INCOME TAXES	436,961	230,335	(2,192)	(228,143)	436,961
INCOME TAX EXPENSE	1,809	—	—	—	1,809
NET INCOME (LOSS)	$ 435,152	$ 230,335	$ (2,192)	$ (228,143)	$ 435,152

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 381,931	$ 3,979	$ —	$ —	$ 385,910
Costs and expenses:					
Lease operating expenses	68,034	843	—	—	68,877
Production taxes	13,121	155	—	—	13,276
Midstream gathering and processing	165,400	572	—	—	165,972
Depreciation, depletion and amortization	245,970	4	—	—	245,974
Impairment of oil and natural gas properties	715,495	—	—	—	715,495
General and administrative	43,896	(490)	3	—	43,409
Accretion expense	1,057	—	—	—	1,057
	1,252,973	1,084	3	—	1,254,060
(LOSS) INCOME FROM OPERATIONS	(871,042)	2,895	(3)	—	(868,150)
OTHER (INCOME) EXPENSE:					
Interest expense	63,529	1	—	—	63,530
Interest income	(1,230)	—	—	—	(1,230)
Insurance proceeds	(5,718)	—	—	—	(5,718)
Loss on debt extinguishment	23,776	—	—	—	23,776
Loss (income) from equity method investments and investments in subsidiaries	31,078	(89)	25,150	(22,154)	33,985
Other expense (income)	145	(16)	—	—	129
	111,580	(104)	25,150	(22,154)	114,472
(LOSS) INCOME BEFORE INCOME TAXES	(982,622)	2,999	(25,153)	22,154	(982,622)
INCOME TAX BENEFIT	(2,913)	—	—	—	(2,913)
NET (LOSS) INCOME	$ (979,709)	$ 2,999	$ (25,153)	$ 22,154	$ (979,709)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 707,868	$ 1,122	$ —	$ —	$ 708,990
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 natural gas properties	1,440,418	—	—	—	1,440,418
General and administrative	41,892	55	20	—	41,967
Accretion expense	820	—	—	—	820
	2,042,595	1,089	20	—	2,043,704
(LOSS) INCOME FROM OPERATIONS	(1,334,727)	33	(20)	—	(1,334,714)
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
Other (income) expense	(1,657)	(346)	—	1,518	(485)
	146,158	(346)	115,544	(115,185)	146,171
(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	$ (1,224,884)	$ 379	$ (115,564)	$ 115,185	$ (1,224,884)

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

	Year Ended December 31, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$ 435,152	$ 230,335	$ (2,192)	$ (228,143)	$ 435,152
Foreign currency translation adjustment	12,519	182	12,337	(12,519)	12,519
Other comprehensive income (loss)	12,519	182	12,337	(12,519)	12,519
Comprehensive income (loss)	$ 447,671	$ 230,517	$ 10,145	$ (240,662)	$ 447,671

	Year Ended December 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$ (979,709)	$ 2,999	$ (25,153)	$ 22,154	$ (979,709)
Foreign currency translation adjustment	2,119	778	1,341	(2,119)	2,119
Other comprehensive income (loss)	2,119	778	1,341	(2,119)	2,119
Comprehensive (loss) income	$ (977,590)	$ 3,777	$ (23,812)	$ 20,035	$ (977,590)

	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)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Year Ended December 31, 2017				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$ 392,680	$ 287,209	$ —	$ —	$ 679,889
Net cash (used in) provided by investing activities	(2,031,615)	(1,674,690)	(2,280)	1,419,417	(2,289,168)
Net cash provided by (used in) financing activities	432,961	1,417,137	2,280	(1,419,417)	432,961
Net (decrease) increase in cash and cash equivalents	(1,205,974)	29,656	—	—	(1,176,318)
Cash and cash equivalents at beginning of period	1,273,882	1,993	—	—	1,275,875
Cash and cash equivalents at end of period	$ 67,908	$ 31,649	$ —	$ —	$ 99,557

	Year Ended December 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ 336,330	$ (9,486)	$ (2)	$ 11,001	$ 337,843
Net cash (used in) provided by investing activities	(905,582)	(22,500)	(15,472)	37,972	(905,582)
Net cash provided by (used in) financing activities	1,730,640	33,500	15,473	(48,973)	1,730,640
Net increase (decrease) in cash and cash equivalents	1,161,388	1,514	(1)	—	1,162,901
Cash and cash equivalents at beginning of period	112,494	479	1	—	112,974
Cash and cash equivalents at end of period	$ 1,273,882	$ 1,993	$ —	$ —	$ 1,275,875

	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

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

The Company owns a 24.9999% interest in Grizzly, which interest is shown below.

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

	2017	2016
	(In thousands)	
Proven properties	$ 6,256,182	$ 4,491,615
Unproven properties	2,912,974	1,580,305
	9,169,156	6,071,920
Accumulated depreciation, depletion, amortization and impairment reserve	(4,136,777)	(3,778,043)
Net capitalized costs	$ 5,032,379	$ 2,293,877
Equity investment in Grizzly Oil Sands ULC		
Proven properties	$ 73,818	$ 70,266
Unproven properties	86,540	80,892
	160,358	151,158
Accumulated depreciation, depletion, amortization and impairment reserve	(1,693)	(1,578)
Net capitalized costs	$ 158,665	$ 149,580

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	2017	2016	2015
		(In thousands)	
Acquisition	$ 1,951,281	$ 152,887	$ 810,755
Development of proved undeveloped properties	994,237	423,998	642,811
Exploratory	—	—	—
Recompletions	14,289	16,386	13,894
Capitalized asset retirement obligation	42,270	10,971	8,800
Total	$ 3,002,077	$ 604,242	$ 1,476,260
Equity investment in Grizzly Oil Sands ULC			
Acquisition	$ 503	$ 357	$ 396
Development of proved undeveloped properties	—	—	47
Exploratory	—	—	—
Capitalized asset retirement obligation	(524)	784	282
Total	$ (21)	$ 1,141	$ 725

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.

	2017	2016	2015
		(In thousands)	
Revenues	$ 1,320,303	$ 385,910	$ 708,990
Production costs	(350,367)	(248,125)	(222,805)
Depletion	(358,792)	(243,098)	(335,288)
Impairment	—	(715,495)	(1,440,418)
	611,144	(820,808)	(1,289,521)
Income tax expense (benefit)			
Current	3,362	—	—
Deferred	(3,602)	—	(220,201)
	(240)	—	(220,201)
Results of operations from producing activities	$ 611,384	$ (820,808)	$ (1,069,320)
Depletion per Mcf of gas equivalent (Mcfe)	$ 0.90	$ 0.92	$ 1.68

Results of Operations from equity method investment in Grizzly Oil Sands ULC			
Revenues	$ —	$ —	$ 1,436
Production costs	—	(13)	(1,549)
Depletion	—	—	(625)
	—	(13)	(738)
Income tax expense	—	—	—
Results of operations from producing activities	$ —	$ (13)	$ (738)

Oil and Gas Reserves

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2017, 2016 and 2015 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, 2017, 2016 and 2015, in accordance with guidelines of the SEC applicable to reserves estimates. Volumes for oil are stated in thousands of barrels (MBbls) and volumes for natural gas are stated in millions of cubic feet (MMcf). The prices used for the 2017 reserve report are $51.34 per barrel of oil, $2.98 per MMbtu and $18.40 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, 2016 and 2015 for reserve report purposes are $42.75 per barrel, $2.48 per MMbtu and $9.91 per barrel for NGLs and $50.28 per barrel, $2.59 per MMbtu and $13.21 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.

	2017			2016			2015		
	Oil	Natural Gas	Natural Gas Liquids	Oil	Natural Gas	Natural Gas Liquids	Oil	Natural Gas	Natural Gas Liquids
	(MBbls)	(MMcf)	(MBbls)	(MBbls)	(MMcf)	(MBbls)	(MBbls)	(MMcf)	(MBbls)
Proved Reserves									
Beginning of the period	5,546	2,167,068	20,127	6,458	1,560,145	17,736	9,497	719,006	26,268
Purchases in oil and natural gas reserves in place	15,132	1,098,644	53,617	—	—	—	—	371,663	—
Extensions and discoveries	951	1,594,734	4,619	1,217	1,082,220	7,677	2,413	997,057	5,486
Revisions of prior reserve estimates	107	314,925	2,737	(3)	(247,703)	(1,439)	(2,553)	(371,430)	(9,594)
Current production	(2,579)	(350,061)	(5,334)	(2,126)	(227,594)	(3,847)	(2,899)	(156,151)	(4,424)
End of period	19,157	4,825,310	75,766	5,546	2,167,068	20,127	6,458	1,560,145	17,736
Proved developed reserves	10,245	1,616,930	36,247	4,882	744,797	14,299	6,120	652,961	12,910
Proved undeveloped reserves	8,912	3,208,380	39,519	664	1,422,271	5,828	338	907,184	4,826
Equity investment in Grizzly Oil Sands ULC									
Beginning of the period	—	—	—	—	—	—	14,558	—	—
Purchases in oil and natural gas reserves in place	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	—	—	—	—	—	—	—	—
Revisions of prior reserve estimates	—	—	—	—	—	—	(14,530)	—	—
Current production	—	—	—	—	—	—	(28)	—	—
End of period	—	—	—	—	—	—	—	—	—
Proved developed reserves	—	—	—	—	—	—	—	—	—
Proved undeveloped reserves	—	—	—	—	—	—	—	—	—

In 2017, the Company purchased 1.5 Tcfe through our acquisition of SCOOP properties discussed in Note 2. Also in 2017, the Company experienced extensions and discoveries of 1.6 Tcfe of estimated proved reserves primarily attributable to the continued development of the Company's Utica Shale acreage. In 2017, the Company experienced upward revisions of 201.3 Bcfe in estimated proved reserves due to an increase in well performance, 214.1 Bcfe due to the increase in pricing and 95.9 Bcfe due to changes in its ownership interests. These positive revisions are partially offset by downward revisions of 133.0 Bcfe due to a decline in well performance specific to one area in the Company's Utica field and a decline of 45.7 Bcfe in estimated proved reserves in 2017 primarily due to the exclusion of ten PUD locations in the Company's Utica field, five of which are operated by the Company and five of which are operated by other operators, that were excluded due to changes in drilling schedules. Additional downward revision of 0.6 Bcfe was due to the removal of two PUD locations in the Company's Southern Louisiana fields that had not been drilled within five years of initial booking. In 2016, the Company experienced extensions and discoveries of 1.1 Tcfe of estimated proved reserves attributable to the continued development of the Company's Utica Shale acreage. The Company experienced downward revisions of 227.9 Bcfe due to lower commodity prices on 67 PUD locations, including the loss of 35 of the 67 PUD locations as they were no longer economic, as well as downward revisions of 17.4 Bcfe due to rescheduling the drilling timeline of four PUD locations in excess of five years of initial booking resulting in the removal of these four PUD locations. In addition, the Company experienced upward revisions of 26.7 Bcfe attributable to improved performance of 34 PUD locations as a result of 14.5% production increases due to well performance of offset producers as well as lower lease operated and capital expenditures. In 2015, the Company experienced extensions and discoveries of 1,044.5 Bcfe of estimated 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 its 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.

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, 2017, 2016 and 2015 using an unweighted average first-of-the-month price for the period January through December 31, 2017, 2016 and 2015.

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

	Year ended December 31,		
	2017	2016	2015
	(In thousands)		
Future cash flows	$ 11,202,692	$ 3,354,168	$ 3,043,450
Future development and abandonment costs	(3,005,217)	(1,165,025)	(877,660)
Future production costs	(2,152,821)	(924,167)	(941,243)
Future production taxes	(289,944)	(69,447)	(58,169)
Future income taxes	(573,965)	(14,545)	(2,648)
Future net cash flows	5,180,745	1,180,984	1,163,730
10% discount to reflect timing of cash flows	(2,537,181)	(492,944)	(399,399)
Standardized measure of discounted future net cash flows	$ 2,643,564	$ 688,040	$ 764,331
Equity investment in Grizzly Oil Sands ULC Standardized measure of discounted cash flows			
Future cash flows	$ —	$ —	$ —
Future development and abandonment costs	—	—	—
Future production costs	—	—	—
Future production taxes	—	—	—
Future income taxes	—	—	—
Future net cash flows	—	—	—
10% discount to reflect timing of cash flows			
Standardized measure of discounted future net cash flows	$ —	$ —	$ —

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 $551.0 million, $458.8 million and $514.5 million during years 2018, 2019 and 2020, respectively.

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

	Year ended December 31,		
	2017	2016	2015
	(In thousands)		
Sales and transfers of oil and gas produced, net of production costs	$ (756,257)	$ (312,291)	$ (486,185)
Net changes in prices, production costs, and development costs	913,714	(146,518)	(1,412,181)
Acquisition of oil and gas reserves in place	703,866	—	83,340
Extensions and discoveries	618,039	186,909	262,895
Previously estimated development costs incurred during the period	390,673	176,218	117,540
Revisions of previous quantity estimates, less related production costs	155,200	(38,448)	(98,162)
Accretion of discount	68,804	76,433	142,717
Net changes in income taxes	(231,545)	(6,495)	412,240
Change in production rates and other	93,030	(12,099)	314,960
Total change in standardized measure of discounted future net cash flows	$ 1,955,524	$ (76,291)	$ (662,836)
Equity investment in Grizzly Oil Sands ULC Changes in standardized measure of discounted cash flows			
Sales and transfers of oil and gas produced, net of production costs	$ —	$ —	$ 114
Net changes in prices, production costs, and development costs	—	—	—
Acquisition of oil and gas reserves in place	—	—	—
Extensions and discoveries	—	—	—
Previously estimated development costs incurred during the period	—	—	47
Revisions of previous quantity estimates, less related production costs	—	—	(103,282)
Accretion of discount	—	—	9,375
Net changes in income taxes	—	—	—
Change in production rates and other	—	—	—
Total change in standardized measure of discounted future net cash flows	$ —	$ —	$ (93,746)

19. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table summarizes quarterly financial data for the years ended December 31, 2017 and 2016:

	2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$ 333,004	$ 323,953	$ 265,498	$ 397,848
Income from operations	181,683	143,175	50,483	173,025
Income tax expense (benefit)	—	—	2,763	(954)
Net income	154,455	105,936	18,235	156,526
Income per share:				
Basic	$ 0.91	$ 0.58	$ 0.10	$ 0.85
Diluted	$ 0.91	$ 0.58	$ 0.10	$ 0.85

	2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$ 156,961	$ (28,158)	$ 193,691	$ 63,416
Loss from operations	(195,794)	(323,412)	(157,995)	(190,949)
Income tax (benefit) expense	(191)	(157)	(3,407)	842
Net loss	(242,267)	(339,776)	(157,296)	(240,370)
Loss per share:				
Basic	$ (2.17)	$ (2.71)	$ (1.25)	$ (1.86)
Diluted	$ (2.17)	$ (2.71)	$ (1.25)	$ (1.86)

20. SUBSEQUENT EVENTS

Derivatives

In January and February 2018, the Company entered into fixed price swaps for 2018 for approximately 1,000 barrels of oil per day at a weighted average price of $62.18 per barrel and for approximately 500 barrels of C3 propane per day at a weighted average price of $35.54 per barrel. For 2019, the Company entered into fixed price swaps for approximately 242,000 MMBtu of natural gas per day at a weighted average price of $2.79 per MMBtu and for approximately 2,000 barrels of oil per day at a weighted average price of $57.75 per barrel. The Company's fixed price swap contracts are tied to the commodity prices on NYMEX for natural gas, NYMEX WTI for oil and Mont Belvieu for propane. The Company will receive the fixed priced amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX for natural gas, NYMEX WTI for oil or Mont Belvieu for propane.

Stock Repurchase Program

In January 2018, the board of directors of the Company approved a stock repurchase program to acquire up to $100.0 million of the Company’s outstanding common stock during 2018. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and will be subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require the Company to acquire any specific number of shares. The Company intends to purchase shares under the repurchase program opportunistically with available funds while maintaining sufficient liquidity to fund its 2018 capital development program. This repurchase program is authorized to extend through December 31, 2018 and may be suspended from time to time, modified, extended or discontinued by the board of directors of the Company at any time. The Company did not make any purchases of its common stock during the year ended December 31, 2017 under any stock repurchase program or otherwise, and has not made any such purchases of its common stock as of February 22, 2018.

Exhibit 21

SUBSIDIARIES OF GULFPORT ENERGY CORPORATION

Name of Subsidiary	Jurisdiction of Organization
Grizzly Holdings, Inc.	Delaware
Jaguar Resources LLC	Delaware
Puma Resources, Inc.	Delaware
Gator Marine, Inc.	Delaware
Gator Marine Ivanhoe, Inc.	Delaware
Westhawk Minerals LLC	Delaware
Gulfport Appalachia, LLC (formerly known as Gulfport Buckeye LLC)	Delaware
Gulfport Midstream Holdings, LLC	Delaware
Gulfport MidCon, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 22, 2018, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Gulfport Energy Corporation on Form 10-K for the year ended December 31, 2017. We consent to the incorporation by reference of said reports in the Registration Statements of Gulfport Energy Corporation on Forms S-8 (File No. 333-206564, effective August 25, 2015; File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001), on Forms S-3ASR (File No. 333-215078, automatically effective December 14, 2016, and File No. 333-217362, automatically effective April 18, 2017) and on Form S-4 (File No. 333-222592, effective February 12, 2018).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 22, 2018

Exhibit 23.2

CONSENT OF NETHERLAND, SEWELL & ASSOCIATES, INC.

We hereby consent to the inclusion in the Form 10-K of Gulfport Energy Corporation (the “Form 10-K”) of our report dated February 9, 2018 on oil and gas reserves of Gulfport Energy Corporation and its subsidiaries as of December 31, 2017 located in the Utica Shale in Eastern Ohio, the SCOOP play in Oklahoma and in Louisiana and information from our prior reserve reports referenced in the Form 10-K, to all references to our firm included in the Form 10-K and to the incorporation by reference of such reports in the Registration Statements of Gulfport Energy Corporation on Forms S-8 (File No. 333-206564, effective August 25, 2015; File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001), on Forms S-3ASR (File No. 333-215078, automatically effective December 14, 2016, and File No. 333-217362, automatically effective April 18, 2017) and on Form S-4 (File No. 333-222592, effective February 12, 2018).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ J. CARTER HENSON, JR., P.E.
J. Carter Henson, Jr., P.E.
Senior Vice President

Houston, Texas
February 22, 2018

Exhibit 31.1

CERTIFICATION

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

1. I have reviewed this Annual Report on Form 10-K of Gulfport Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statement made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in the Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: February 22, 2018

/s/ Michael G. Moore

Michael G. Moore
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION

I, Keri Crowell, Chief Financial Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K of Gulfport Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statement made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in the Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: February 22, 2018

/s/ Keri Crowell
Keri Crowell
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PERIODIC REPORT

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

(1) the Annual Report on Form10-K of the Company for the year ended December 31, 2017 (the “Report”) fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 22, 2018

/s/ Michael G. Moore
Michael G. Moore
Chief Executive Officer and President

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

Exhibit 32.2

CERTIFICATION OF PERIODIC REPORT

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

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 22, 2018

/s/ Keri Crowell

Keri Crowell
Chief Financial Officer

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

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 99.1

February 9, 2018

Mr. Michael G. Moore
Gulfport Energy Corporation
3001 Quail Springs Parkway
Oklahoma City, Oklahoma 73134

Dear Mr. Moore:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2017, to the Gulfport Energy Corporation (Gulfport) interest in certain oil and gas properties located in Louisiana, Ohio, and Oklahoma. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute over 99 percent of all proved reserves owned by Gulfport. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Gulfport's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Gulfport interest in these properties, as of December 31, 2017, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	8,239.8	33,449.1	1,495,249.1	2,523,312.7	1,692,775.7
Proved Developed Non-Producing	1,715.4	2,796.0	121,392.0	255,865.8	166,166.3
Proved Undeveloped	8,911.7	39,519.0	3,208,380.6	2,965,371.6	1,017,662.7
Total Proved	18,867.0	75,764.1	4,825,021.7	5,744,550.6	2,876,605.0

Totals may not add because of rounding.

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

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. No study was made to determine whether probable and possible reserves might be established for the Louisiana properties. As requested, probable and possible reserves that exist for the Ohio and Oklahoma properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

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

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2017. For oil and NGL volumes, the average Shell Trading (US) Company West Texas/New Mexico Intermediate posted price of $47.96 per barrel is used for the Louisiana properties and the average West Texas Intermediate spot price of $51.34 per barrel is used for the Ohio and Oklahoma properties. These average prices are adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.976 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $47.92 per barrel of oil, $18.40 per barrel of NGL, and $1.843 per MCF of gas.

Operating costs used in this report are based on operating expense records of Gulfport. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and Gulfport's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and are not escalated for inflation.

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

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

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Gulfport interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Gulfport receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

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

Exhibit 99.1

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

The data used in our estimates were obtained from Gulfport, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Mr. Richard B. Talley, Jr., a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. Mr. Edward C. Roy III, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

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

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

By: /s/ Richard B. Talley, Jr.	By: /s/ Edward C. Roy III
Richard B. Talley, Jr., P.E. 102425	Edward C. Roy III, P.G. 2364
Senior Vice President	Vice President
Date Signed: February 9, 2018	Date Signed: February 9, 2018

RBT:JMH

DEFINITIONS OF OIL AND GAS RESERVES

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

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

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

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

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

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

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

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

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

Supplemental definitions from the 2007 Petroleum Resources Management System:

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

Developed Non-Producing Reserves - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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

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

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

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

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

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

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

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting

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

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

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

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

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

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

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

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

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

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

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

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

DEFINITIONS OF OIL AND GAS RESERVES

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

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

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

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

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

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

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

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

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

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

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

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS OF OIL AND GAS RESERVES

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

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

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

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

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

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

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

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

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

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

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

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