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, 2019

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	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	GPOR	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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).
Yes ☒ No ☐

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 our common stock held by non-affiliates on June 28, 2019 was $782,634,443. As of February 14, 2020, there were 159,710,955 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation’s Proxy Statement for the 2020 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

GULFPORT ENERGY CORPORATION
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FORWARD-LOOKING STATEMENTS

This Form 10-K may include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (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), the effect of our remediation plan for a material weakness, 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.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

Investors should note that we announce financial information in SEC filings, press releases and public conference calls. We may use the Investors section of our website (www.gulfportenergy.com) to communicate with investors. It is possible that the financial and other information posted there could be deemed to be material information. The information on our website is not part of this Annual Report on Form 10-K.

PART I

ITEM 1. BUSINESS

Our Business

A Delaware corporation formed in 1997, we are an independent natural gas-weighted exploration and production company focused on the exploration, development, acquisition and production of natural gas, crude oil and natural gas liquids ("NGL") in the United States with primary focus in the Appalachia and Mid-Continent basins. Our corporate strategy is focused on the economic development of our asset base in an effort to generate sustainable free cash flow. We also seek to opportunistically expand our inventory of economic drilling locations in the basins in which we operate. Our principal properties are located in Eastern Ohio, where we target development in the Utica formation (the “Utica”) and Central Oklahoma where we target development in the SCOOP Woodford and Springer formations (the "SCOOP"). We seek to achieve reserve growth and increase our cash flow through our annual drilling programs. In addition, among other interests, we hold an acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC ("Grizzly"), and an approximate 21.8% equity interest in Mammoth Energy Services, Inc. ("Mammoth Energy"), an energy services company listed on the Nasdaq Global Select Market (TUSK), both of which are non-core to our business strategy.

As of December 31, 2019, we had 4.5 trillion cubic feet of natural gas equivalent ("Tcfe") of proved reserves with a standardized measure of discounted future net cash flows of approximately $1.7 billion and a present net value of estimated future net revenues, discounted at 10% ("PV-10"), of approximately$1.7 billion. See "*Oil, Natural Gas and NGL Reserves*" below 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.

Information About Us

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. From time to time, we also post announcements, updates, events, investor information and presentations on our website in addition to copies of our recent news releases. 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.

Business Strategy

Gulfport aims to create shareholder value through the development of our significant resource plays. Our substantial inventory of hydrocarbon resources, including unproved acreage positions in each of our key basins, provides a strong foundation to create future value. Concentrated blocks of unproved acreage provide us the opportunity to apply best in class techniques including optimum well spacing, leading completion practices and lateral length optimization to maximize overall capital efficiency. We have improved our capital and operating efficiency metrics over the last several years and today have a low cost structure in both our Utica and SCOOP operating areas. We believe our low cost structure provides a significant competitive advantage in the current commodity price environment and it is our strategy to continue to seek capital and operating efficiencies to grow this advantage.

We continue to focus on reducing our leverage profile, increasing cash flow from operations, improving margins through financial discipline and operating efficiencies while at the same time maintaining strong environmental and safety performance. To accomplish these goals, we intend to allocate capital expenditures to projects we believe offer the highest rate of return, to deploy leading drilling and completion techniques and technologies in our development efforts, and to take advantage of merger, acquisition and divestiture opportunities to strengthen our cost structure, deepen our inventory and improve our asset portfolio.

We believe that our dedication to financial discipline, the flexibility and efficiency of our capital program, our low cost structure and our continued focus on safety and environmental stewardship provides opportunities for sustainable value creation.

Our 2020 capital expenditure program is expected to be $285 million to $310 million. We expect to fund these expenditures with our operating cash flow and borrowings under our revolving credit agreement. We expect this drilling program to result in 1,100 to 1,150 MMcfe per day of production in 2020.

We plan to run on average approximately one operated rig in our Utica area and 1.5 rigs in our SCOOP area in 2020. In the Utica, we intend to spud 16 gross operated horizontal wells (14.8 net), and commence sales on 18 gross and net horizontal wells in 2020. In the SCOOP, we intend to spud 10 gross operated horizontal wells (7.8 net), and commence sales on four gross horizontal wells (3.8 net) in 2020.

Operating Areas

We focus our development, production and acquisition efforts in the geographic operating areas described below.

Utica (primarily Eastern Ohio) - The Utica Shale is a hydrocarbon bearing rock formation located in the Appalachian Basin of the United States and Canada. We have approximately 205,000 net reservoir acres located primarily in Belmont, Harrison, Jefferson and Monroe Counties in Eastern Ohio where the Utica Shale ranges in thickness from 600 to over 750 feet. During the fourth quarter of 2019 we produced approximately 1,090 MMcfe per day net to our interests in this area.

SCOOP (Oklahoma) - The SCOOP, or South Central Oklahoma Oil Province, is a loosely defined area that encompasses many of the top hydrocarbon producing counties in Oklahoma within the Anadarko basin. The SCOOP play mainly targets the Devonian to Mississippian aged Woodford, Sycamore and Springer formations. We have approximately 76,000 net reservoir acres (comprised of approximately 41,500 in the Woodford formation and approximately 34,500 in the Springer formation) located primarily in Garvin, Grady and Stephens Counties. The Woodford Shale across our position 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 consists of hydrocarbon-bearing interbedded shales and siliceous limestones ranging in thickness from 150 to over 450 feet and is overlain by the Caney Shale. The Springer formation across our position is comprised of a series of lenticular sand and shale units. The primary targets are a series of porous, low clay and organic-rich packages within the Goddard Shale member ranging in thickness from 50 to over 250 feet. During the fourth quarter of 2019, we produced approximately 255 MMcfe per day net to our interests in this area.

Additional Properties - In addition to our core properties discussed above, we also own working interests and overriding royalty interest in various fields including the Bakken formation in North Dakota and Montana, the Niobrara formation in Colorado and other formations in Texas. We previously held interests located in the West Cote Blanche Bay ("WCBB") and Hackberry fields of Louisiana. However, we sold these non-core interests in July 2019.

Drilling Activity

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, regardless of whether they produce a reasonable rate of return.

	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	—	—	47	47	81	81
Dry	—	—	—	—	—	—
Total	—	—	47	47	81	81
Development:						
Productive	25	22.4	34	30	124	115.4
Dry	—	—	—	—	2	2
Total	25	22.4	34	30	126	117.4
Exploratory:						
Productive	1	0.8	2	1.5	—	—
Dry	—	—	—	—	—	—
Total	1	0.8	2	1.5	—	—

The following table presents activity by operating area for the year ended December 31, 2019:

Field	Operated				Non-Operated			
	Drilled		Turned to Sales		Drilled		Turned to Sales	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Utica Shale (1)	16	14.6	47	41.6	5	0.9	14	3.3
SCOOP (2)	10	8.6	14	12.6	42	1.6	39	1.2
Niobrara Formation	—	—	—	—	—	—	—	—
Bakken Formation	—	—	—	—	—	—	—	—
Total	26	23.2	61	54.2	47	2.5	53	4.5

(1) Of the 16 gross wells we drilled in 2019, six were completed as producing wells and 10 were in various stages of completion as of December 31, 2019.
(2) Of the 10 gross wells we drilled in 2019, five were completed as producing wells, four were in various stages of completion and one was being drilled as of December 31, 2019.

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, 2019.

Field	Average 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 Gross	Developed Acreage Net	Undeveloped Acreage Gross	Undeveloped Acreage Net
Utica Shale	45.93/56.32	126	40.36	503	313.41	—	—	2	1.58	107,076	85,381	130,734	119,428
SCOOP	26.21/32.64	118	24.28	480	153.16	13	3.69	56	36.58	50,721	35,602	7,373	5,999
Niobrara Formation	24.41/29.18	5	1.46	—	—	—	—	—	—	1,998	999	1,292	646
Bakken Formation	1.11/1.97	18	0.35	—	—	—	—	—	—	386	77	3,505	701
Overrides/Royalty Non-operated	Various	401	0.02	5	0.02	2	—	—	—	—	—	—	—
Total		668	66.47	988	466.59	15	3.69	58	38.16	160,181	122,059	142,904	126,774

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

Most of our leases have a three- to five-year primary term, many of which include options to extend the primary term. We manage lease expirations to ensure that we do not experience unintended material expirations. Our leasehold management efforts include scheduling our operations and drilling to establish production in paying quantities in order to hold leases prior to the expiration dates, paying the prescribed lease extension payments, planning non-core divestitures or strategic acreage trades with other operators to high-grade our lease inventory and letting some leases expire that are no longer part of our development plans. The following table sets forth the potential expiration periods of gross and net undeveloped leasehold acres as of December 31, 2019

	Undeveloped Acres	
	Gross Acres	Net Acres
Years Ending December 31:		
2020	16,572	14,803
2021	13,773	12,685
2022	17,960	16,039
After 2022	20,088	18,975
Held by production or operations	74,511	64,272
Total	142,904	126,774

Oil, Natural Gas and NGL Reserves

The tables below set forth information as ofDecember 31, 2019, with respect to our estimated proved reserves, the associated estimated future net revenue, the PV-10 and the standardized measure of discounted future net cash flows (“standardized measure”). None of the estimated future net revenue, PV-10 nor the standardized measure are intended to represent the current market value of the estimated oil, natural gas and NGL reserves we own. All of our estimated reserves are located within the United States.

	December 31, 2019			
	Oil (MMbbl)	Natural Gas (Bcf)	NGL (MMbbl)	Total (Bcfe)
Proved developed	8	1,757	30	1,984
Proved undeveloped	10	2,291	32	2,544
Total proved(1)	18	4,048	62	4,528

	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue(2)	$ 2,086	$ 1,461	$ 3,547
Present value of estimated future net revenue (PV-10)(2)	$ 1,383	$ 320	$ 1,704
Standardized measure(2)			$ 1,704

(1) Utica and SCOOP accounted for approximately 71% and 29%, respectively, of our estimated proved reserves by volume as of December 31, 2019.

(2) Estimated future net revenue represents the estimated future revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of December 31, 2019, and assuming commodity prices as set forth below. For the purpose of determining prices used in our reserve reports, we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2019. The prices used in our PV-10 measure were $55.85 per barrel and $2.58 per MMBtu, before basis differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity derivative instruments in place as of December 31, 2019. The amounts shown do not give effect to non-property-related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue typically differs from the standardized measure because the former does not include the effects of estimated future income tax expense. There was no effect of estimated future income tax expense as of December 31, 2019, primarily as a result of significant net operating loss carryforwards that can be used to offset income taxes on future taxable income.

Management uses PV-10, which is calculated without deducting estimated future income tax expenses, as a measure of the value of the Company's current proved reserves and to compare relative values among peer companies. We also understand that securities analysts and rating agencies use this measure in similar ways. While estimated future net revenue and the present value thereof are based on prices, costs and discount factors which may be consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP.

A reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented above. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

Grizzly had no proved reserves as of December 31, 2019. For further discussion of our interest in Grizzly, see "*Our Equity Investments*" below.

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 2019.

The following table summarizes the changes in our estimated proved reserves during 2019 (in Bcfe):

Proved Reserves, December 31, 2018	**4,743**
Sales of oil and natural gas reserves in place	(77)
Extensions and discoveries	1,097
Revisions of prior reserve estimates	(734)
Current production	(502)
Proved Reserves, December 31, 2019	**4,528**

Sales of oil and natural gas reserves in place. These are revisions to proved reserves resulting from the divestiture of minerals in place during a period. During 2019, we sold approximately 76.8 Bcfe of proved oil and natural gas reserves through various sales of our Southern Louisiana assets, non-operated interests in our Utica assets and overriding royalty interests in North Dakota.

Extensions and discoveries. These are additions to our proved reserves that result from extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery. Extensions of approximately 1.1 Tcfe of proved reserves were primarily attributable to the continued development of our Utica Shale and SCOOP acreage. We added 72 drilling locations in our Utica acreage for 793.5 Bcfe and 37 drilling locations in our SCOOP acreage for 302.9 Bcfe. This change reflects our ongoing efforts to optimize the development program with well selection based on economic returns, commodity mix and surface considerations.

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

We experienced total downward revisions of 733.8 Bcfe in estimated proved reserves, of which 347.2 Bcfe was a result of the exclusion of nine PUD locations in our Utica field and 22 PUD locations in our SCOOP field when changes in our schedule moved development of these PUD locations beyond five years of initial booking. The development plan change reflects our commitment to capital discipline and funding future activities within cash flow.

An additional 296.4 Bcfe in downward revisions was the result of commodity price changes. Commodity prices experienced volatility throughout 2019 and the 12-month average price for natural gas decreased from $3.10 per MMBtu for 2018 to $2.58 per MMBtu for 2019, the 12-month average price for NGL decreased from $32.02 per barrel for 2018 to $21.25 per barrel for 2019, and the 12-month average price for crude oil decreased from $65.56 per barrel for 2018 to $55.85 per barrel for 2019.

We also experienced downward revisions of 90.2 Bcfe from a combination of working interest changes, optimization of our well design in the current commodity price environment and well performance.

Additional information regarding estimates of proved reserves, proved developed reserves and proved undeveloped reserves at December 31, 2019, 2018 and 2017 and changes in proved reserves during the last three years are contained in the Supplemental Information on Oil and Gas Exploration and Production Activities, or Supplemental Information, in Note 19 of the notes to our consolidated financial statements included in this report.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2019, our proved undeveloped reserves totaled 10 MMbbl of oil, 2,291 Bcf of natural gas and 32 MMbbl of NGL, for a total of 2,544 Bcfe. Approximately 70% and 30% of our PUD reserves at year-end 2019 were located in Utica and SCOOP, 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 changes in commodity price outlook and costs, delays in the availability of infrastructure, well permitting delays and new data from recently completed wells.

The following table summarizes the changes in our estimated proved undeveloped reserves during2019 (in Bcfe):

Proved Undeveloped Reserves, December 31, 2018	**2,628**
Sales of oil and natural gas reserves in place	(69)
Extensions and discoveries	1,078
Conversion to proved developed reserves	(654)
Revisions of prior reserve estimates	(439)
Proved Undeveloped Reserves, December 31, 2019	**2,544**

*Sales of oil and natural gas reserves in place.*During 2019, we sold approximately 68.8 Bcfe of proved undeveloped oil and natural gas reserves associated with various non-operated interests, the majority of which were in our Utica field.

Extensions and discoveries. Our extensions of approximately 1.1 Tcfe were primarily attributed to the addition of 72 PUD drilling locations in the Utica field and 37 PUD drilling locations in the SCOOP field as a result of our current development plan that refocused some activity within our existing fields. This change reflects our ongoing efforts to optimize the development program with well selection based on economic returns, commodity mix and surface considerations.

Conversion to proved developed reserves. Our 2019 development activities resulted in the conversion of approximately 654.0 Bcfe into proved developed producing reserves, attributable to 49 PUD locations in the Utica field and 12 PUD locations in the SCOOP field. These 61 PUDs represent a conversion rate of 20% for 2019.

Revision of prior reserve estimates. We experienced proved undeveloped downward revisions of 347.2 Bcfe from the exclusion of 9 PUD locations in our Utica field and 22 PUD locations in our SCOOP field due to the SEC five-year development rule. The development plan change, as approved by our senior management and Board of Directors, reflects our commitment to capital discipline and funding future activities within cash flow. We also experienced 146.8 Bcfe of downward revisions as a result of commodity price changes. These downward revisions were partially offset by positive revisions of 54.8 Bcfe in estimated proved reserves from a combination of well performance, changes in ownership interest and development well design changes.

Costs incurred relating to the development of PUDs were approximately$353.1 million in 2019.

All PUD drilling locations included in our2019 reserve report are scheduled to be drilled within five years of initial booking.

As of December 31, 2019, 1% of our total proved reserves were classified as proved developed non-producing.

Reserves Estimation

Reserve estimates at December 31, 2019 and December 31, 2018 were prepared by Netherland, Sewell & Associates, Inc. ("NSAI") for all of our operating areas. Reserve estimates at December 31, 2017 were prepared by NSAI with respect to our assets in the Utica Shale in Eastern Ohio, the SCOOP Woodford and SCOOP Springer plays in Oklahoma and our WCBB and Hackberry fields. Our personnel prepared reserve estimates with respect to our Niobrara field as well as our overriding royalty and non-operated interests at December 31, 2017.

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, operating and development costs and other considerations, including availability and costs of infrastructure and status of permits. Our Senior 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 20 years of reservoir and operations experience. In addition, our geophysical staff has approximately 100 years combined industry experience and our reservoir staff has approximately 40 years combined experience.

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, operating, marketing and capital 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 NSAI in coordination with our experienced reservoir engineers;
- direct reporting responsibilities by our reservoir engineering department to our Chief Operating 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.

PV-10 Sensitivities.

As noted above, our December 31, 2019 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 2019 of $55.85 per barrel and $2.58 per MMBtu. Holding production and development costs constant, if SEC pricing were $61.44 per barrel and $2.84 per MMBtu, or a 10% increase, this would have resulted in an increase of 69.6 Bcfe of our total proved reserves and a $0.7 billion increase in PV-10 value at December 31, 2019. Holding production and development costs constant, if SEC pricing were $50.27 per barrel and $2.32 per MMBtu, or a 10% decrease, this would have resulted in a decrease of 106.5 Bcfe of our total proved reserves and a $0.7 billion decrease in PV-10 value at December 31, 2019.

Production, Prices and Production Costs

The following table presents our production volumes in our core operating areas during the periods indicated:

Field	Year Ended December 31,				
	2019				
	Net Production				
	Natural Gas (MMcf)	Oil and Condensate (Mbbls)	NGL (MGal)	Natural gas equivalents (MMcfe)	MMcfe per Day
Utica Shale	387,473	247	76,112	399,828	1,095
SCOOP	70,669	1,610	136,948	99,891	274
Niobrara Formation	—	14	—	86	—
Bakken Formation	35	41	67	292	1
Louisiana and Other	1	274	2	1,645	5
Total	458,178	2,186	213,129	501,742	1,375

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

	2019	2018	2017
		($ In thousands)	
Natural gas sales			
Natural gas production volumes (MMcf)	458,178	443,742	350,061
Total natural gas sales	$ 918,263	$ 1,121,815	$ 845,999
Natural gas sales without the impact of derivatives ($/Mcf)	$ 2.00	$ 2.53	$ 2.42
Impact from settled derivatives ($/Mcf)	$ 0.23	$ (0.04)	$ 0.07
Average natural gas sales price, including settled derivatives ($/Mcf)	$ 2.23	$ 2.49	$ 2.49
Oil and condensate sales			
Oil and condensate production volumes (Mbbls)	2,186	2,801	2,579
Total oil and condensate sales	$ 117,937	$ 177,793	$ 124,568
Oil and condensate sales without the impact of derivatives ($/Bbl)	$ 53.95	$ 63.48	$ 48.29
Impact from settled derivatives ($/Bbl)	$ 1.86	$ (9.51)	$ 1.59
Average oil and condensate sales price, including settled derivatives ($/Bbl)	$ 55.81	$ 53.97	$ 49.88
NGL sales			
NGL production volumes (MGal)	213,129	251,720	224,038
Total NGL sales	$ 101,448	$ 178,915	$ 136,057
NGL sales without the impact of derivatives ($/Gal)	$ 0.48	$ 0.71	$ 0.61
Impact from settled derivatives ($/Gal)	$ 0.06	$ (0.05)	$ (0.03)
Average NGL sales price, including settled derivatives ($/Gal)	$ 0.54	$ 0.66	$ 0.58
Natural gas, oil and condensate and NGL sales			
Natural gas equivalents (MMcfe)	501,742	496,505	397,543
Total natural gas, oil and condensate and NGL sales	$ 1,137,648	$ 1,478,523	$ 1,106,624
Natural gas, oil and condensate and NGL sales without the impact of derivatives ($/Mcfe)	$ 2.27	$ 2.98	$ 2.78
Impact from settled derivatives ($/Mcfe)	$ 0.24	$ (0.12)	$ 0.07
Average natural gas, oil and condensate and NGL sales price, including settled derivatives ($/Mcfe)	$ 2.51	$ 2.86	$ 2.85
Production Costs:			
Average production costs ($/Mcfe)	$ 0.17	$ 0.18	$ 0.20
Average production taxes ($/Mcfe)	$ 0.06	$ 0.07	$ 0.05
Average midstream gathering and processing ($/Mcfe)	$ 0.58	$ 0.58	$ 0.63
Total production costs, midstream costs and production taxes ($/Mcfe)	$ 0.81	$ 0.83	$ 0.88

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, 2019:

	Year Ended December 31,		
	2019	2018	2017
Utica Shale			
Net Production			
Natural gas (MMcf)	387,473	379,417	309,450
Oil (Mbbls)	247	299	473
NGL (Mgal)	76,112	113,379	139,634
Total (MMcfe)	399,828	397,406	332,238
Average Sales Price Without the Impact of Derivatives:			
Natural gas ($/Mcf)	$ 1.99	$ 2.50	$ 2.38
Oil ($/Bbl)	$ 51.11	$ 60.22	$ 44.26
NGL ($/Gal)	$ 0.47	$ 0.67	$ 0.60
Average Production Costs ($/Mcfe)	$ 0.14	$ 0.14	$ 0.15

	Year Ended December 31,		
	2019	2018	2017 (1)
SCOOP			
Net Production			
Natural gas (MMcf)	70,669	64,258	40,501
Oil (Mbbls)	1,610	1,710	1,083
NGL (Mgal)	136,948	138,261	84,283
Total (MMcfe)	99,891	94,268	59,038
Average Sales Price Without the Impact of Derivatives:			
Natural gas ($/Mcf)	$ 2.08	$ 2.67	$ 2.68
Oil ($/Bbl)	$ 53.32	$ 62.36	$ 48.70
NGL ($/Gal)	$ 0.48	$ 0.75	$ 0.62
Average Production Costs ($/Mcfe)	$ 0.18	$ 0.20	$ 0.19

(1) We acquired our SCOOP assets through an acquisition completed on February 17, 2017. See Note 2 in the notes to our consolidated financial statements for additional discussion of this acquisition.

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, 2019, 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 ("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. 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 future plans for the facility. Grizzly also owns the May River property comprising approximately 47,000 acres prospective for oil sands development. 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 received final approval in December 2019. If pursued, this project could begin production as early as 2023. 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 ("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 ("LPG") into the oil sands area for use in Thermal applications by SAGD producers. We elected to cease funding capital calls in 2019, and we have no obligation to fund any of the projects Grizzly is pursuing. Failure to fund capital calls may lead to dilution of our equity ownership interest.

Mammoth Energy. In connection with Mammoth Energy's initial public offering ("IPO") in October 2016, we received 9,150,000 shares of Mammoth Energy common stock in return for our contribution to Mammoth Energy of our 30.5% interest in Mammoth Energy Partners LLC. In June 2017, we received an additional 2,000,000 shares of Mammoth Energy common stock in connection with our contribution of all of our equity interests in three other entities to Mammoth Energy. We sold 76,250 shares of our Mammoth Energy common stock in the IPO and an additional 1,354,574 shares in a subsequent underwritten public offering in 2018. As of December 31, 2019, we owned 9,829,548 shares, or approximately 21.8%, of Mammoth Energy’s outstanding common stock.

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

Marketing

The principal function of our marketing operations is to provide natural gas, oil and NGL marketing services, including securing and negotiating of commodity transactions, gathering, hauling, processing and transportation services, contract administration and nomination services for Gulfport’s interest and other interest owners in Gulfport-operated wells. In addition, there are a variety of oil, natural gas and NGL purchase and sale contracts with third parties for various commercial purposes, including risk mitigation and satisfaction of our pipeline delivery commitments. These marketing activities often enhance the value of our production by aggregating volumes and allowing improved flexibility in relation to deal structure, size and counterparty exposure whether through intermediary markets or direct end markets.

Generally, natural gas and NGL production is sold to purchasers under both spot and term transactions. Oil production is sold under both spot and term transactions with the majority being shorter term in nature. We have entered into long-term gathering, processing and transportation contracts with various parties that require us to deliver fixed, determinable quantities of production over specified periods of time. Some contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under these commitments. See Note 16 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our commitments.

Major Customers

For the year ended December 31, 2019, sales to Morgan Stanley Capital accounted for approximately 14% of our total natural gas, oil and NGL revenues, before the effects of hedging. For the year ended December 31, 2018, sales to BP Energy Company ("BP") and ECO-Energy accounted for approximately 17% and 10%, respectively, of our total natural gas, oil and NGL revenues, before the effects of hedging. For the year ended December 31, 2017, sales to BP accounted for approximately 40% of our total natural gas, oil and NGL revenues, before the effects of hedging.

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 have midstream and further downstream operations and market a variety of hydrocarbon products on a regional, national or worldwide basis. 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 renewable sources such as wind or solar energy in addition to 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.

Title to Oil and Natural Gas Properties

It is customary in the oil and natural gas industry to make only a preliminary 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.

Regulation - Environment, Health and Safety

Exploration and Production, Environmental, Health and Safety, and Occupational Laws and Regulations

Our operations are subject to federal, tribal, state, and local laws and regulations. These laws and regulations relate to matters that include, but are not limited to, the following:

- reporting of workplace injuries and illnesses;
- industrial hygiene monitoring;
- worker protection and workplace safety;
- approval or permits to drill and to conduct operations;
- provision of financial assurances (such as bonds) covering drilling and well operations;
- calculation and disbursement of royalty payments and production taxes;
- seismic operations and data;
- location, drilling, cementing and casing of wells;
- well design and construction of pad and equipment;
- construction and operations activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species, their habitats, or sites of cultural significance;
- method of completing wells;
- hydraulic fracturing;
- water withdrawal;
- well production and operations, including processing and gathering systems;
- emergency response, contingency plans and spill prevention plans;
- air emissions and fluid discharges;
- climate change;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage, maintenance, monitoring and the restoration of properties associated with well pads, pipelines, impoundments and access roads;
- plugging and abandoning of wells; and
- transportation of production.

Failure to comply with these laws and regulations can lead to the imposition of remedial liabilities, fines, or criminal penalties or to injunctions limiting our operations in affected areas. Moreover, multiple environmental laws provide for citizen suits which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. We consider the costs of environmental protection and of safety and health compliance to be necessary, manageable parts of our business. We have been able to plan for and comply with environmental, safety and health laws and regulations without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to compliance with the protection of the environment, safety and health have increased over the years and may continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters. See the Risk Factors described in Item 1A of this report for further discussion of governmental regulation and ongoing regulatory changes, including with respect to environmental matters.

Our operations are also subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in a unit, the rate of production allowable from oil and gas wells, and the unitization or pooling of oil and gas properties. In the United States, some states allow the forced pooling or integration of tracts to facilitate exploration. Other states rely on voluntary pooling of lands and leases which may make it more difficult to develop oil and gas properties. In addition, federal and state conservation laws generally limit the venting or flaring of natural gas, and state conservation laws impose certain requirements regarding the ratable purchase of production. These regulations limit the amounts of oil and gas we can produce from our wells and the number of wells or the locations at which we can drill.

Regulatory proposals in some states and local communities have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Federal and state agencies have continued to assess the potential impacts of hydraulic fracturing, which could spur further action toward federal, state and/or local legislation and regulation. Further restrictions of hydraulic fracturing could reduce the amount of natural gas, oil and NGL that we are ultimately able to produce in commercial quantities from our properties.

Certain of our U.S. natural gas and oil leases are granted or approved by the federal government and administered by the Bureau of Land Management (BLM) or Bureau of Indian Affairs (BIA) of the Department of the Interior. Such leases require compliance with detailed federal regulations and orders that regulate, among other matters, drilling and operations on lands covered by these leases and calculation and disbursement of royalty payments to the federal government, tribes or tribal members. The federal government has been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding, venting and flaring, oil and gas measurement and royalty payment obligations for production from federal lands. In addition, permitting activities on federal lands are subject to frequent delays.

Delays in obtaining permits or an inability to obtain new permits or permit renewals could inhibit our ability to execute our drilling and production plans. Failure to comply with applicable regulations or permit requirements could result in revocation of our permits, inability to obtain new permits and the imposition of fines and penalties.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. If any of these should occur, we could incur legal defense costs and could suffer substantial losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. Our horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

We maintain a control of well insurance policy with a $25 million single well limit and a $35 million multiple wells limit that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. This insurance may not be adequate to cover all losses or exposure to liability. We also carry a $101 million comprehensive general liability umbrella insurance policy. In addition, we maintain a $10 million pollution liability insurance policy providing coverage for gradual pollution related risks and in excess of the general liability policy for sudden and accidental pollution risks. We provide workers' compensation insurance coverage to employees in all states in which we operate. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks, and policy limits scale to our working interest percentage in certain situations. In addition, our insurance does not cover penalties or fines that may be assessed by a governmental authority. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. Our insurance coverage may not be sufficient to cover every claim made against us or may not be commercially available for purchase in the future.

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 each of 2019 and 2018 were immaterial. 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. We pay these companies a retainer plus additional amounts when they provide us with clean up services.

Employees

At December 31, 2019, we had 298 employees.

Executive Officers

David M. Wood, Chief Executive Officer, President and Director

David M. Wood, 62, has served as the Chief Executive Officer and President of the Company, and as a member of our board of directors, since December 2018. Prior to joining the Company, Mr. Wood served as the Chief Executive Officer and Chairman of the Board of Directors of Arsenal Resources LLC, which we refer to as Arsenal, a West Virginia focused natural gas producer and portfolio company of First Reserve Corporation ("First Reserve"), an energy-focused private equity firm, where he most recently served as Chairman of its board of directors and previously held the role of the Chief Executive Officer. Prior to his tenure at Arsenal, Mr. Wood served as a Senior Advisor to First Reserve from 2013 to 2016, serving on several of its portfolio company boards. Prior to his position at First Reserve, Mr. Wood spent more than 17 years at Murphy Oil Corporation (NYSE: MUR) ("Murphy Oil"), a global oil and natural gas exploration and production company, where he served as Chief Executive Officer, President and a member of the board of directors from 2009 to 2012. From 1980 to 1994, Mr. Wood held various senior positions with Ashland Exploration and Production, an oil and natural gas exploration and production company. Mr. Wood began his career as a well-site geologist in Saudi Arabia. Mr. Wood has served on the board of directors of Lilis Energy, Inc. (NYSE: LLEX), an exploration and development company operating in the Delaware Basin since June 2018. Mr. Wood also served on the board of directors of the general partner of Crestwood Equity Partners LP (NYSE: CEQP) and its wholly-owned subsidiary, Crestwood Midstream Partners LP, an owner and operator of crude oil and natural gas midstream assets. Mr. Wood also served on the board of directors of several private oil and natural gas companies, including Deep Gulf Energy LP (prior to its acquisition by Kosmos Energy Ltd.) and Berkana Energy Corp. (when it was majority owned by Murphy Oil). Mr. Wood previously served on the board of directors and as an executive committee member of the American Petroleum Institute. He was also a member of the National Petroleum Council and is a member of the Society of Exploration Geophysicists. Mr. Wood holds a B.S. in Geology from the University of Nottingham in England and completed Harvard University’s Advanced Management Program.

Quentin R. Hicks, Executive Vice President and Chief Financial Officer

Quentin R. Hicks, 45, has served as the Executive Vice President and Chief Financial Officer of the Company since August 2019. Prior to joining the Company, Mr. Hicks served as the Executive Vice President and Chief Financial Officer of Halcón Resources Corporation (“Halcón”), a position he held since March 2019, having previously served as Executive Vice President, Finance, Capital Markets and Investor Relations of Halcón since January 2018. Prior to that, Mr. Hicks held various roles at Halcón focused primarily on finance and investor relations. Prior to Halcón, Mr. Hicks worked for GeoResources Inc., where he served as Director of Acquisitions and Financial Planning from 2011 to 2012. From 2004 to 2011, he worked in investment banking with Bear Stearns, Sanders Morris Harris and Madison Williams, where he was a Director in their energy investment banking practice. Prior to that, Mr. Hicks worked as Manager of Financial Reporting for Continental Airlines. Mr. Hicks began his career in 1998 working as an auditor for Ernst and Young LLP. Mr. Hicks graduated from Texas A&M University with a Bachelor of Business Administration and a Master of Science degree in Accounting. In addition, Mr. Hicks holds a Master of Business Administration degree in Finance from Vanderbilt University and also holds a Certified Public Accountant license from the State of Texas.

Donnie G. Moore, Executive Vice President and Chief Operating Officer

Donnie G. Moore, 55, has served as Executive Vice President and Chief Operating Officer of the Company since January 2018. He also served as Interim Chief Executive Officer of the Company from October 29, 2018, the date our former Chief Executive Officer and President left the Company, to December 18, 2018, the date of the appointment of Mr. Wood as our new Chief Executive Officer and President. From 2007 until December 2017, Mr. Moore worked at Noble Energy, Inc. ("Noble"), where he most recently served as Vice President of Noble’s Texas operations for its Eagle Ford and Delaware Basin assets. Prior to that, Mr. Moore held various leadership roles at Noble including Vice President of the Marcellus Business Unit, Manager for Operations of the Wattenberg/DJ Business Unit, Manager of Operations for the Gunflint discovery in the Deepwater Gulf of Mexico and Development Manager for Noble’s Mid-Continent and Gulf Coast positions. From 1989 until 2007, Mr. Moore served in a variety of roles with ARCO Oil and Gas Company, Vastar Resources, Inc. and BP America. Mr. Moore holds a Bachelor of Science degree in Petroleum Engineering from Louisiana Tech University.

Patrick K. Craine, Executive Vice President, General Counsel and Corporate Secretary

Patrick K. Craine, 47, has served as Executive Vice President, General Counsel and Corporate Secretary of the Company since May 2019. Mr. Craine has over 20 years of extensive senior-level experience handling a broad range of securities, corporate, regulatory, governance, compliance and litigation matters, with particular expertise in the energy industry. He joined Gulfport from Chesapeake Energy Corporation (NYSE: CHK) ("Chesapeake"), where he served as Deputy General Counsel – Chief Risk and Compliance Officer from 2013 until 2019. Prior to joining Chesapeake, Mr. Craine was a partner with Bracewell LLP, a global law firm, where his practice focused on securities and corporate regulatory matters and investigations. Before Mr. Craine entered private practice, he served as a lawyer with the U.S. Securities and Exchange Commission and the Financial Industry Regulatory Authority where he held leadership positions in their Oil and Gas Task Forces.

Michael J. Sluiter, Senior Vice President of Reservoir Engineering

Michael J. Sluiter, 47, has served as Senior Vice President of Reservoir Engineering of the Company since December 2018. Mr. Sluiter joined the Company from Noble Energy, Inc., where he held various engineering and leadership positions from March 2007 to November 2018, including, most recently, the Permian Basin Business Unit Manager. Prior to, Noble Mr. Sluiter worked for Santos Australia and Santos USA from February 2000 to March 2007, and started his career as a wireline field services engineer for Schlumberger in Thailand. He has over 18 years combined of experience in unconventional resource development, reservoir engineering, subsurface development, business development and acquisitions. Mr. Sluiter holds a Bachelor of Science degree in Chemical Engineering from the University of Sydney, Australia.

ITEM 1A. RISK FACTORS

There are numerous factors that affect our business and operating results, many of which are beyond our control. The following is a description of significant factors that might cause our future results to differ materially from those currently expected. The risks described below are not the only risks facing our company. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also affect our business operations. If any of these risks actually occur, our business, financial position, operating results, cash flows, reserves or our ability to pay our debts and other liabilities could suffer, the trading price and liquidity of our securities could decline and you may lose all or part of your investment in our securities.

Natural gas, oil and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse effect on our business.

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 and NGL. We incur substantial expenditures to replace reserves, sustain production and fund our business plans. Low oil, natural gas and NGL prices can negatively affect the amount of cash available for capital expenditures, debt service and debt repayment and our ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on our financial condition, results of operations, cash flows and reserves. In addition, periods of low natural gas, oil and NGL prices may result in ceiling test write-downs of our oil and natural gas properties.

Historically, the markets for natural gas, oil and NGL have been volatile, and they are likely to continue to be volatile. For example, during 2018, West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, prices ranged from $44.48 to $77.41 per barrel and the Henry Hub spot market price of natural gas ranged from $2.49 to $6.24 per MMBtu. During 2019, WTI prices ranged from $46.31 to $66.24 per barrel and the Henry Hub spot market price of natural gas ranged from $1.75 to $4.25 per MMBtu. As of February 14, 2020, the WTI price was $52.03 per barrel and the Henry Hub spot market price of natural gas was $1.93 per MMBtu.

Wide fluctuations in natural gas, oil and NGL prices may result from factors that are beyond our control, including:

- domestic and worldwide supplies of oil, natural gas and NGL, including U.S. inventories of oil and natural gas reserves;
- the level of prices, and expectations about future prices, of oil and natural gas;
- changes in the level of consumer and industrial demand, including impacts from global or national health epidemics and concerns, such as the recent coronavirus;

- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the expected rates of declining current production;
- changes in the level of consumer and industrial demand;
- the price and availability of alternative fuels;
- technological advances affecting energy consumption;
- risks associated with operating drilling rigs;
- the effectiveness of worldwide conservation measures;
- the availability, proximity and capacity of pipelines, other transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- U.S. exports of oil, natural gas, liquefied natural gas and NGL;
- the price and level of foreign imports;
- the nature and extent of 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 or economic instability or armed conflict in oil and natural gas producing regions, including the Middle East, Africa, South America and Russia;
- weather conditions;
- acts of terrorism; and
- domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas, oil and NGL price movements with any certainty. As of February 27, 2020, including January and February derivative contracts that have settled, approximately 50% of our forecasted 2020 natural gas, oil and NGL production revenue was hedged, including 52% and 80% of our forecasted 2020 natural gas and oil production, at average prices of $2.86 per Mcf and $59.82 per Bbl, respectively. Even with natural gas, oil and NGL derivatives currently in place to mitigate price risks associated with a portion of our 2020 cash flows, we have substantial exposure to natural gas prices, and to a lesser extent, oil and NGL prices, in 2021 and beyond. In addition, a prolonged extension of lower prices could reduce the quantities of reserves that we may economically produce. 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.

We have a significant amount of indebtedness. Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.

As of December 31, 2019, we had approximately $2.0 billion in principal amount of debt outstanding, primarily attributable to our senior notes. We also had $120.0 million in borrowings outstanding under our revolving credit facility and our borrowing base availability was$636.4 million after giving effect to an aggregate of $243.6 million of letters of credit.

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 their restrictive covenants, could result in a default under our revolving credit facility or the indentures governing our senior notes;

- 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 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.

Our ability to pay our expenses and fund our working capital needs and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as commodity prices, other economic conditions and governmental regulation. If our borrowing base under our revolving credit facility decreases as a result of lower prices of natural gas, oil or NGL, operating difficulties, declines in reserves or for any other reason, our liquidity and ability to conduct additional exploration and development activities may be limited. To the extent that the value of the collateral pledged under our revolving credit facility declines as a result of lower oil and natural gas prices, asset dispositions or otherwise, we may be required to pledge additional collateral to maintain the current availability of the commitments thereunder, and we cannot assure you that we will be able to maintain a sufficiently high valuation to maintain the current borrowing base. 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 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. Any of the above risks could materially adversely affect our business, financial condition, cash flows and results of operations.

We have significant capital needs, and our ability to access the capital and credit markets to raise capital on favorable terms is limited by our debt level and industry conditions.

Disruptions in the capital and credit markets, in particular with respect to the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. Low commodity prices have caused and may continue to cause lenders to increase the interest rates under our revolving credit facility, enact tighter lending standards, refuse to refinance existing debt around maturity on favorable terms or at all and reduce or cease to provide funding to borrowers. If we are unable to access the capital and credit markets on favorable terms, it could have a material adverse effect on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt. Additionally, challenges in the economy have led and could further lead to reductions in the demand for natural gas, oil and NGL, or further reductions in the prices of natural gas, oil and NGL, which could have a negative impact on our financial position, results of operations and cash flows.

If we are unable to generate enough cash flow from operations to service our indebtedness or are unable to use future borrowings to refinance our indebtedness or fund other capital needs, we may have to undertake alternative financing plans, which may have onerous terms or may be unavailable.

Our earnings and cash flow could vary significantly from year to year due to the volatility of hydrocarbon commodity prices. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments or to make necessary capital expenditures. A range of economic, competitive, business and industry factors will affect our future financial performance and, as a result, our ability to generate cash flow from operations and service our debt. Factors that may cause us to generate cash flow that is insufficient to meet our debt obligations include the events and risks related to our business, many of which are beyond our control. Any cash flow insufficiency would have a material adverse impact on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt.

If we do not generate sufficient cash flow from operations to service our outstanding indebtedness, or if future borrowings are not available to us in an amount sufficient to enable us to pay or refinance our indebtedness, we may be required to undertake various alternative financing plans, which may include:

- refinancing or restructuring all or a portion of our debt;
- seeking alternative financing or additional capital investment;
- selling strategic assets;
- reducing or delaying capital investments; or
- revising or delaying our strategic plans.

We cannot assure you that we would be able to implement any alternative financing plans, if necessary, on commercially reasonable terms or at all, or that any such alternative financing plans would allow us to meet our debt obligations. If we are unable to generate sufficient cash flow to satisfy our debt obligations or to obtain necessary and sufficient alternative financing, our business, financial condition, results of operations, cash flows and liquidity could be materially and adversely affected. Any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could significantly harm our ability to incur additional indebtedness on acceptable terms. Further, if for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors under those agreements to declare all outstanding indebtedness thereunder to be due and payable (which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements), the lenders under our revolving credit facility could terminate their commitments to extend credit, and the lenders could foreclose against our assets securing their borrowings and we could be forced into bankruptcy or liquidation. In addition, 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. If the amounts outstanding under our revolving credit facility or any of our other significant indebtedness were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full the amounts owed to the lenders or to our other debt holders. 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 revolving credit facility and the indentures governing our senior notes could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our revolving credit facility and the indentures governing our senior notes impose operating and financial restrictions on us. These restrictions limit our ability and that of our restricted subsidiaries to, among other things

- 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. The restrictions contained in the covenants could:

- limit our ability to plan for, or react to, market conditions, to meet capital needs or otherwise to restrict our activities or business plan;
- adversely affect our ability to finance our operations, enter into acquisitions or divestitures to engage in other business activities that would be in our interest; or
- withstand a continuing future downturn in our business.

Also, our revolving credit facility requires us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Specifically, our revolving credit facility requires us to maintain a ratio of net funded debt to EBITDAX at the end of each fiscal quarter for a twelve-month period of not greater than 4.00 to 1.00, and a ratio of EBITDAX to interest expense at the end of each fiscal quarter for a twelve-month period of not less than 3.00 to 1.00. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a continued downturn in our business or a downturn in the economy in general or otherwise conduct necessary corporate activities. Further declines in natural gas, oil and NGL prices, or a prolonged period of low natural gas, oil and NGL prices could eventually result in our failing to meet one or more of the financial covenants under our revolving credit facility, which could require us to refinance or amend such obligations resulting in the payment of consent fees or higher interest rates, or require us to raise additional capital at an inopportune time or on terms not favorable to us.

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 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.

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.

Any significant reduction in our borrowing base under our revolving credit facility as a result of 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, 2019, we had $120.0 million in borrowings and $243.6 million of letters of credit outstanding under our revolving credit facility. 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 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, 2019, 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 $120.0 million in borrowings under this facility. Total funds available for borrowing under our revolving credit facility as of December 31, 2019, after giving effect to $243.6 million of outstanding letters of credit, were $636.4 million. In addition, the indentures governing our 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. If new debt or other liabilities are added to our current debt levels, the related risks that we now face could intensify.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase.

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 such, our interest expense is sensitive to fluctuations in the London Interbank Offered Rate. At December 31, 2019, amounts borrowed under our revolving credit facility bore interest at the weighted average rate of 3.30%. A 1% increase in the average interest rate would have increased our interest expense by approximately $1.2 million based on outstanding borrowings under our revolving credit facility throughout the year ended December 31, 2019. An increase in our interest rate at the time we have variable interest rate borrowings outstanding under our revolving credit facility will increase our costs, which may have a material adverse effect on our results of operations and financial condition. As of December 31, 2019, we did not hedge our interest rate risk.

Changes in the method of determining the London Interbank Offered Rate, or the replacement of the London Interbank Offered Rate with an alternative reference rate, may adversely affect interest expense related to outstanding debt.

Amounts drawn under our revolving credit facility may bear interest at rates based on the London Interbank Offered Rate (“LIBOR”). On July 27, 2017, the Financial Conduct Authority in the United Kingdom announced that it would phase out LIBOR as a benchmark by the end of 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021. Our revolving credit facility provides for a mechanism to amend the facility to reflect the establishment of an alternative rate of interest upon the occurrence of certain events related to the phase-out of LIBOR. However, we have not yet pursued any technical amendment or other contractual alternative to address this matter and are currently evaluating the impact of the potential replacement of the LIBOR interest rate. In addition, the overall financial markets may be disrupted as a result of the phase-out or replacement of LIBOR. Uncertainty as to the nature of such potential phase-out and alternative reference rates or disruption in the financial market could have a material adverse effect on our financial condition, results of operations and cash flows.

Under our method of accounting for oil and natural gas properties, declines in commodity prices 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 proved 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 unweighted arithmetic average of the closing prices on the first day of each month for the 12-month period ending at the balance sheet date, 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 result in 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 recorded a ceiling test impairment of $2.0 billion for the year ended December 31, 2019. If prices of natural gas, oil and natural gas liquids continue to decrease, we will be required to further write down the value of our oil and natural gas properties. Future non-cash asset impairments could negatively affect our results of operations.

Our 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 drilling and completions capital expenditures for 2020 to be in the range of $265 million to $285 million and an additional $20 million to $25 million for leasehold expenditures, primarily lease extensions and infill leasing within our Utica Shale and Scoop development plans.

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

- our proved reserves;
- the volume of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold;
- 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 2020 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.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. Thus, our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

The actual quantities of and future net revenues from our proved reserves may be less than our estimates.

The estimates of our proved reserves and the estimated future net revenues from our proved reserves included in this report are based upon various assumptions, including assumptions required by the SEC relating to natural gas, oil and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating natural gas, oil and NGL reserves is complex and involves significant decisions and assumptions associated with geological, geophysical, engineering and economic data for each well. Therefore, these estimates are subject to future revisions.

Actual future production, natural gas, oil and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas, oil and NGL reserves most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2019, approximately 56.2% of our total estimated proved reserves were proved undeveloped reserves ("PUDs") and may not be ultimately developed or produced. Recovery of PUDs 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. You should be aware that the estimated development costs may not equal our actual costs, development may not occur as scheduled and results may not 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. If we choose not to develop our PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove them from our reported proved reserves. In addition, under the SEC's reserve reporting rules, because PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any PUDs that are not developed within this five-year time frame.

You should not assume that the present values included in this report represent the current market value of our estimated reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The price on the date of estimate is calculated as the average natural gas and oil price during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. The December 31, 2019 present value is based on a $2.58 per MMBtu of gas price and a $55.85 per Bbl of oil price, before considering basis differential adjustments. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

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 the production and the expenses from the development and production of oil and natural gas properties will affect both the timing of future net cash flows from our proved reserves and their present value. Any changes in demand for oil and natural gas, governmental regulations or taxation will also affect the future net cash flows from our production. In addition, the 10% discount factor that is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor. Interest rates in effect from time to time and the risks associated with our business or the oil and gas industry in general will affect the appropriateness of the 10% discount factor.

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

We have a substantial inventory of undeveloped properties. Development and exploratory drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. 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 acquire significant amounts of unproven properties 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 initial investments. Additionally, there can be no assurance that undeveloped properties acquired 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 undeveloped properties 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 and completion operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, title problems, equipment failures or accidents, shortages of midstream transportation, equipment or personnel, environmental issues, state or local bans or moratoriums on hydraulic fracturing and produced water disposal, and a decline in commodity prices, among others. The profitability of wells, particularly in certain of the areas in which we operate, will be reduced or eliminated if commodity prices decline. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for natural gas, oil and NGL, costs associated with producing natural gas, oil and NGL 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. All costs of development and exploratory drilling activities are capitalized under the full cost method, even if the activities do not result in commercially productive discoveries, which may result in a future impairment of our oil and natural gas properties if commodity prices decrease.

We rely to a significant extent on seismic data and other technologies in evaluating undeveloped properties and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of undeveloped properties, or drilling a well, whether oil or natural gas is present or may be produced economically. If we incur significant expense in acquiring or developing properties that do not produce as expected or at profitable levels, it could have a material adverse effect on our results of operations and financial condition.

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, 2019, we had entered into firm transportation contracts to deliver approximately 1,205,000 MMBtu to 1,505,000 MMBtu per day for 2020 and 2021. 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.

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 development activities we employ, such as offset drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of offset drilling, adjacent 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, such as our SCOOP play in Oklahoma. The area was historically developed by vertical wells drilled through multiple stacked reservoirs and recent development has focused on the Woodford formation; however, development in the Sycamore and Springer formations has been limited. As emerging formations, 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 Sycamore and Springer formations exists over our acreage position, it is difficult to predict our future drilling results.

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, 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.

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.

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.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. 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. Approximately 20% of our Utica Shale undeveloped acreage that is subject to expiration will be subject to expiration in 2020, with 17% of such acreage expiring in 2021, 22% in 2022 and 41% thereafter, although our Utica Shale leases generally grant us the right to extend these leases for an additional five-year period. Although 97% of our SCOOP acreage is held by existing production from both vertical and horizontal wells, the remaining acreage is subject to expiration. Of the remaining 3% of our SCOOP acreage not held by production, 59% will be be subject to expiration in 2020, 17% in 2021, 7% in 2022 and 17% thereafter. During the year ended December 31, 2019, leases representing 66% of our total Niobrara Formation undeveloped acreage as of December 31, 2018 expired due to failure to establish production. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Low commodity prices may cause us to delay our drilling plans and, as a result, lose our right to develop the related properties. 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.

Our commodity price risk management activities may limit the benefit we would receive from increases in commodity prices, may require us to provide collateral for derivative liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.

To manage our exposure to price volatility, we enter into natural gas, oil and NGL price derivative contracts. Our natural gas, oil and NGL derivative arrangements may limit the benefit we would receive from increases in commodity prices. The fair value of our natural gas, oil and NGL derivative instruments can fluctuate significantly between periods. Our decision to mitigate cash flow volatility through derivative arrangements, if any, is based in part on our view of current and future market conditions and our desire to stabilize cash flows necessary for the development of our proved reserves. We may choose not to enter into derivatives if the pricing environment for certain time periods is not deemed to be favorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities to monetize gain positions for the purpose of funding our capital program.

Natural gas, oil and NGL derivative transactions expose us to the risk that our counterparties, which are generally financial institutions, may be unable to satisfy their obligations to us. During periods of declining commodity prices, the value of our commodity derivative asset positions increase, which increases our counterparty exposure. Although the counterparties to our hedging arrangements are required to secure their obligations to us under certain scenarios, if any of our counterparties were to default on its obligations to us under the derivative contracts or seek bankruptcy protection, it could have an adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future cash flows being exposed to commodity price changes.

The ultimate outcome of pending legal and governmental proceedings is uncertain, and there are significant costs associated with these matters.

We are defending against claims by royalty owners alleging, among other things, that we underpaid royalty owners. The resolution of disputes regarding past payments could cause our future obligations to royalty owners to increase and would negatively impact our future results of operations.

In addition, there is an ongoing SEC investigation with respect to certain actions by former Company management, including alleged improper personal use of Company assets, and potential violations by former management and the Company of the Sarbanes-Oxley Act of 2002. The outcome of any pending or future litigation or governmental regulatory matter is uncertain and may adversely affect our results of operations. In addition, we have incurred substantial legal expenses in the past three years, and such expenses may continue to be significant in the future. Further, attention to these matters by members of our senior management has been required, reducing the time they have available to devote to managing our business.

Oil and natural gas operations are uncertain and involve substantial costs and risks. Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our oil and natural gas operating activities are subject to numerous costs and risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. Drilling for oil, natural gas and NGL can be unprofitable, not only from dry holes, but from productive wells that do not return a profit because of insufficient revenue from production or high costs. Substantial costs are required to locate, acquire and develop oil and gas properties, and we are often uncertain as to the amount and timing of those costs. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Declines in commodity prices and overruns in budgeted expenditures are common risks that can make a particular project uneconomic or less economic than forecasted. While both exploratory and developmental drilling activities involve these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. For the 16% of our daily production volumes from properties which we did not serve as operator as of December 31, 2019, we are dependent on the operator for operational and regulatory compliance. In addition, our oil and gas properties can become damaged, our operations may be curtailed, delayed or canceled and the costs of such operations may increase as a result of a variety of factors, including, but not limited to:

- unexpected drilling conditions, pressure conditions or irregularities in reservoir formations;
- loss of drilling fluid circulation;
- equipment failures or accidents;
- fires, explosions, blowouts, cratering or loss of well control, as well as the mishandling or underground migration of fluids and chemicals;
- risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives;
- adverse weather conditions and natural disasters, such as tornadoes, earthquakes, hurricanes and extreme temperatures;
- issues with title or in receiving governmental permits or approvals;
- restricted takeaway capacity for our production, including due to inadequate midstream infrastructure or constrained downstream markets;
- environmental hazards or liabilities, including liabilities for environmental damage caused by previous owners of properties purchased by us;
- restrictions in access to, or disposal of, water used or produced in drilling and completion operations;
- shortages or delays in the availability of services or delivery of equipment; and
- unexpected or unforeseen changes in regulatory policy, and political or public opinions.

The occurrence of one or more of these factors could result in a partial or total loss of our investment in a particular property, as well as significant liabilities.

While we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. For certain risks, such as political risk, business interruption, war, terrorism and piracy, we have limited or no insurance coverage. Also, in the future we may not be able to obtain insurance at premium levels that 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.

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.

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 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 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 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.

We are subject to extensive governmental regulation and ongoing regulatory changes, which could adversely impact our business.

Our operations are subject to extensive federal, state, tribal, local and other laws, rules and regulations, including with respect to environmental matters, worker health and safety, wildlife conservation, the gathering and transportation of oil, gas and NGL, conservation policies, reporting obligations, royalty payments, unclaimed property and the imposition of taxes. Such regulations include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling, completion and well operations. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling or completion activities, we may not be able to conduct our operations as planned. In addition, we may be required to make large, sometimes unexpected, expenditures to comply with applicable governmental laws, rules, regulations, permits or orders.

In addition, changes in public policy have affected, and in the future could further affect, our operations. Regulatory changes could, among other things, restrict production levels, impose price controls, alter environmental protection requirements and increase taxes, royalties and other amounts payable to the government. Our operating and compliance costs could increase further if existing laws and regulations are revised or reinterpreted or if new laws and regulations become applicable to our operations. We do not expect that any of these laws and regulations will affect our operations materially differently than they would affect other companies with similar operations, size and financial strength. Although we are unable to predict changes to existing laws and regulations, such changes could significantly impact our profitability, financial condition and liquidity. As is discussed below this is particularly true of changes related to pipeline safety, seismic activity, hydraulic fracturing, climate change and endangered species designations.

Pipeline Safety. The pipeline assets owned by our midstream service providers are subject to stringent and complex regulations related to pipeline safety and integrity management. The Pipeline and Hazardous Materials Safety Administration (PHMSA) has established a series of rules that require pipeline operators to develop and implement integrity management programs for gas, NGL and condensate transmission pipelines as well as certain low stress pipelines and gathering lines transporting hazardous liquids, such as oil, that, in the event of a failure, could affect "high consequence areas." Additional action by PHMSA with respect to pipeline integrity management requirements may occur in the future. In July 2018, PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline. PHMSA has not yet issued the final rule. In October 2019, three final rules making up the "Gas Mega Rule" - one establishing procedures to implement the expanded emergency order enforcement authority; the second, concerning gas transmission, extending the requirement to conduct integrity assessments beyond HCAs to pipelines in Moderate Consequence Areas ("MCAs"); and the third, concerning hazardous liquids, extending the required use of leak detection systems beyond HCAs to all regulated non-gathering hazardous liquid pipelines and updating reporting and inspection requirements - were finalized. The cost of these requirements or other potential new or amended regulations could be significant, and any such costs incurred by our midstream service providers could result in increased midstream gathering and processing expenses for us. Moreover, violations of pipeline safety regulations by our midstream service providers could result in the imposition of significant penalties which may impact the cost or availability of pipeline capacity necessary for our operations.

Seismic Activity. Earthquakes in some of our operating areas and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry. For example, the Oklahoma Corporation Commission (OCC) issued guidance to operators in the SCOOP and STACK areas for management of certain seismic activity that may be related to hydraulic fracturing or water disposal activities. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation or other requirements that could lead to operational delays, increase our operating and compliance costs or otherwise adversely affect our operations. In addition, we could be subject to third-party lawsuits seeking damages or other remedies as a result of alleged induced seismic activity in our areas of operation.

Hydraulic Fracturing. Several states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing operations. Three states (New York, Maryland and Vermont) have banned the use of high-volume hydraulic fracturing. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. There have also been certain governmental reviews that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. Governments may continue to study hydraulic fracturing. We cannot predict the outcome of future studies, but based on the results of these studies to date, federal and state legislatures and agencies may seek to further regulate or even ban hydraulic fracturing activities. In addition, if existing laws and regulations with regard to hydraulic fracturing are revised or reinterpreted or if new laws and regulations become applicable to our operations through judicial or administrative actions, our business, financial condition, results of operations and cash flows could be adversely affected. A decision is pending.

We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, our business and operations could be subject to delays, increased operating and compliance costs and potential bans. Additional regulation could also lead to greater opposition to hydraulic fracturing, including litigation.

Climate Change. Continuing political and social attention to the issue of climate change has resulted in legislative, regulatory and other initiatives to reduce greenhouse gas emissions, such as carbon dioxide and methane. Policy makers at both the U.S.

federal and state levels have introduced legislation and proposed new regulations designed to quantify and limit the emission of greenhouse gases through inventories, limitations or taxes on greenhouse gas emissions. Several states where we operate have imposed venting and flaring limitations designed to reduce methane emissions from oil and gas exploration and production activities. Legislative and state initiatives to date have generally focused on the development of cap and trade or carbon tax programs. Cap and trade programs offer greenhouse gas emission allowances that are gradually reduced over time. A cap and trade program could impose direct costs on us through the purchase of allowances and could impose indirect costs by incentivizing consumers to shift away from fossil fuels. A carbon tax could directly increase our costs of operation and similarly incentivize consumers to shift away from fossil fuels.

In addition, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities.

These various legislative, regulatory and other activities addressing greenhouse gas emissions could adversely affect our business, including by imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations, which could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Limitations on greenhouse gas emissions could also adversely affect demand for oil and gas, which could lower the value of our reserves and have a material adverse effect on our profitability, financial condition and liquidity. Furthermore, increasing attention to climate change risks has resulted in increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely affect our business.

Endangered Species. The Endangered Species Act (ESA) prohibits the taking of endangered or threatened species or their habitats. While some of our assets and lease acreage may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where we intend to conduct construction activity or the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

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.

In our Utica operations, we attempt to reuse/recycle all produced water from production and completion activities through our fracture stimulation operations when active. While our objective is to recycle 100% of all produced water, we do inject water into third party commercially operated disposal wells in line with all state and federal mandated practices and cease produced water recycle whenever fracture stimulation operations are idle. In the state of Ohio, all water used during drilling operations is disposed of through injection into third party salt water disposal wells regulated by applicable state agencies.

In our SCOOP operations, Oklahoma regulations allow for the storage of produced water in permitted lined impoundments. These storage impoundments allowed us to recycle approximately 75% of our produced water in 2019 from all of our producing wells. All of our wells completed in 2019 in our SCOOP asset were completed with recycled produced water from these impoundments with minimal use of local freshwater sources. These recycling facilities allowed us to dramatically reduce the amount of produced water that had to be injected into state regulated commercial disposal wells, and decreased our reliance of local freshwater sources required for our completions operations.

Oil and natural gas production operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Our ability to produce natural gas, oil and NGL economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

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. For water sourcing, we first seek to use non-potable water supplies for our operational needs. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must then be obtained from other sources and transported to the drilling site. An inability to secure sufficient amounts of water or to dispose of or recycle the water used in our operations could adversely impact our operations in certain areas. The imposition of new environmental regulations could further restrict our ability to conduct operations such as hydraulic fracturing by restricting the disposal of things such as produced water and drilling fluids

Future U.S. and state tax legislation may adversely affect our business, results of operations, financial condition and cash flow.

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, legislative proposals have been introduced in the U.S. Congress in the past that, if enacted, would (i) eliminate the immediate deduction for intangible drilling and development costs, (ii) repeal the percentage depletion allowance for oil and natural gas properties, and (iii) extend the amortization period for certain geological and geophysical expenditures. 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. In addition, at the state level, legislative changes imposing increased taxes on oil and gas production have periodically been considered in Ohio and Oklahoma. These proposed changes in the U.S. federal and state 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.

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

Our largest fields by production are located in Eastern Ohio and Oklahoma. 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, tornados 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.

The oil and gas exploration and production industry is very competitive, and some of our competitors have greater financial and other resources than we do.

We face competition in every aspect of our business, including, but not limited to, buying and selling reserves and leases, obtaining goods and services needed to operate our business and marketing natural gas, oil or NGL. Competitors include multinational oil companies, independent production companies and individual producers and operators. Some of our competitors have greater financial and other resources than we do and, due to our debt levels and other factors, may have greater access to the capital and credit markets. 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. As a result, these competitors may be able to address these competitive factors more effectively or weather industry downturns more easily than we can. We also face indirect competition from alternative energy sources, including wind, solar and electric power.

Our performance depends largely on the talents and efforts of highly skilled individuals and on our ability to attract new employees and to retain and motivate our existing employees. Competition in our industry for qualified employees is intense. If we are unsuccessful in attracting and retaining skilled employees and managerial talent, our ability to compete effectively may be diminished. We also compete for the equipment required to explore, develop and operate properties. Typically, during times of rising commodity prices, drilling and operating costs will also increase. During these periods, there is often a shortage of drilling rigs and other oilfield equipment and services, which could adversely affect our ability to execute our development plans on a timely basis and within budget.

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 endedDecember 31, 2019 accounted for approximately 14% of our total natural gas, oil 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.

Risks related to potential acquisitions or dispositions may adversely affect our business. Our failure to successfully identify, complete and integrate future acquisitions of properties or businesses could reduce our earnings and slow our growth.

From time to time, we evaluate acquisitions and dispositions of assets, businesses and other investments, including equity investments and joint ventures. 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 or capital expenditures, the timing and amount of which we may not be able to control. These transactions may not result in the anticipated benefits or efficiencies. 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. In addition, acquisitions may be financed by borrowings, requiring us to incur more debt, or by the issuance of our common stock. Any such acquisition or disposition involves risks and we cannot assure you that:

- any acquisition would be successfully integrated into our operations and internal controls;

- the due diligence conducted prior to an acquisition would uncover situations that could result in financial or legal exposure, such as title defects and potential environmental and other liabilities;

- post-closing purchase price adjustments will be realized in our favor;

- any investment, acquisition, disposition or integration would not divert management resources from the operation of our business; and

- any investment, acquisition, or disposition or integration would not have a material adverse effect on our financial condition, results of operations, cash flows or reserves.

If any of these risks materialize, the benefits of such acquisition or disposition may not be fully realized, if at all, and our financial condition, results of operations, cash flows and reserves could be negatively impacted.

Further, 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.

In addition, 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.

We may be unable to dispose of nonstrategic assets on attractive terms and may be required to retain liabilities for certain matters

We regularly review our property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect our ability to dispose of nonstrategic assets or complete announced dispositions, including the availability of purchasers willing to purchase the nonstrategic assets at prices acceptable to us and restrictions under our revolving credit facility. Sellers typically retain liabilities for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, third parties are often unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

A deterioration in general economic, business or industry conditions would 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. Historically, concerns about global economic growth have had a significant 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 materially adversely impact our results of operations, liquidity and financial condition.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. 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 in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices, or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations. 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.

Negative public perception regarding us or our industry could have an adverse effect on our operations.

Negative public perception regarding us or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, waste disposal, oil spills, seismic activity, climate change, explosions of natural gas transmission lines and the development and operation of pipelines and other midstream facilities may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Additionally, environmental groups, landowners, local groups and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business.

Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in energy-related activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities.

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.

Our operations may be adversely affected by pipeline, trucking and gathering system capacity constraints and may be subject to interruptions that could adversely affect our cash flow.

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. In certain resource plays, the capacity of gathering and transportation systems is insufficient to accommodate potential production from existing and new wells. 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. Capital constraints could limit the construction of new pipelines and gathering systems and the providing or expansion of trucking services by third parties in the Utica and the other areas in which we operate. Until this new capacity is available, we may experience delays in producing and selling our natural gas, oil and NGL. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity or sell natural gas, oil or NGL production at significantly lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations.

A portion of our natural gas, oil and NGL production in any region may be interrupted, or shut in, from time to time for numerous reasons, including weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could materially adversely affect our cash flow.

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 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 an approximate 24.9% interest in Grizzly. As of December 31, 2019, 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. At December 31, 2019, we reviewed our investment in Grizzly for impairment, resulting in an aggregate other than temporary impairment write down of $32.4 million for the year ended December 31, 2019. 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. We elected to cease funding capital calls in 2019, and we have no obligation to fund any of the projects Grizzly is pursuing. Failure to fund capital calls may lead to dilution of our equity ownership interest.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we are unable to obtain and maintain adequate protection for our data, our business may be harmed.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil, natural gas and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our customers, employees and third-party partners. 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 our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized access to our seismic data, reserves information, customer or employee data or other proprietary or commercially sensitive information could lead to data corruption, communication interruption, or other disruptions in our exploration or production operations or planned business transactions, any of which could have a material adverse impact on our results of operations. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations, which may include drilling, completion, production and corporate functions. A cyber-attack involving our information systems and related infrastructure, or that of our business associates, could result in supply chain disruptions that delay or prevent the transportation and marketing of our production, non-compliance leading to regulatory fines or penalties, loss or disclosure of, or damage to, our or any of our customer's, supplier's or royalty owners' data or confidential information that could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

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-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber-attacks. In addition, new laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and potentially elevate costs, and any failure to comply with these laws and regulations could result in significant penalties and legal liability.

Our business is subject to complex and evolving laws and regulations regarding privacy and data protection.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and potentially elevate our costs. For example, the California Consumer Privacy Act ("CCPA") was signed into law on June 28, 2018 and largely took effect on January 1, 2020. The CCPA, among other things, contains new disclosure obligations for businesses that collect personal information about California residents and enhanced consumer protections for those individuals, and provides for statutory fines for data security breaches or other CCPA violations. Meanwhile, over fifteen other states have considered privacy laws like the CCPA. We will continue to monitor and assess the impact of these state laws, which may impose substantial penalties for violations, impose significant costs for investigations and compliance, require us to change our business practices, allow private class-action litigation and carry significant potential liability for our business should we fail to comply with any such applicable laws.

Any failure, or perceived failure, by us to comply with applicable data protection laws could result in heightened risk of litigation, including private rights of action, and proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments and negative publicity, require us to change our business practices, increase the costs and complexity of compliance, and adversely affect our business. As noted above, we are also subject to the possibility of cyber incidents or attacks, which themselves may result in a violation of these laws. Additionally, if we acquire a company that has violated or is not in compliance with applicable data protection laws, we may incur significant liabilities and penalties as a result.

If our investments in entities are not successful or decrease in market value, we may be required to write off or lose the value of a portion or all of our investments, which could have a materially adverse effect on our results of operations.

Through our wholly owned subsidiaries, we have directly or indirectly made investments in certain entities that are accounted for by the equity method of accounting. We have recorded impairment charges to reflect the other than temporary decreases in the fair value of such entities, including an impairment loss of $160.8 million with respect to our investment in Mammoth Energy and an impairment loss of $32.4 million with respect to our investment in Grizzly recorded during the year endedDecember 31, 2019. If the financial position of any such entity declines, we could be required to write down all or part of our investment in that entity, which could have a materially adverse effect on our results of operations.

An interruption in operations at our headquarters could adversely affect our business.

Our headquarters are located in Oklahoma City, Oklahoma, an area that experiences severe weather events, including tornadoes and earthquakes. Our information systems and administrative and management processes are primarily provided to our various drilling projects and producing wells throughout the United States from this location, which could be disrupted if a catastrophic event, such as a tornado, power outage or act of terror, destroyed or severely damaged our headquarters. Any such catastrophic event could harm our ability to conduct normal operations and could adversely affect our business.

We have identified a material weakness in internal controls. If we fail to remediate this material weakness or otherwise fail to develop, implement and maintain effective internal controls in future periods, our ability to report our financial condition and results of operations accurately and on a timely basis could be adversely affected.

We have identified a material weakness in our internal controls over the completeness and accuracy of the accounting of transfers of unevaluated capitalized costs into the amortization base. Accordingly, based on our management's assessment, we believe that, as of December 31, 2019, our disclosure controls and procedures were not effective. We also determined that this material weakness existed as of September 30, 2019. The material weakness and our remediation plans are described in Item 9A, *Controls and Procedures*.

A "material weakness" is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements would not be prevented or detected on a timely basis. We cannot assure you that we will adequately remediate the material weakness or that additional material weaknesses in our internal controls will not be identified in the future. Any failure to maintain or implement required new or improved controls, or any difficulties we encounter in the implementation, could result in additional material weaknesses, or could result in material misstatements in our financial statements. These misstatements could result in restatements of our financial statements, cause us to fail to meet our reporting obligations or cause investors to lose confidence in our reported financial information.

We are in the process of remediating the identified material weakness in our internal controls, but we are unable at this time to estimate when the remediation will be completed. If we fail to remediate this material weakness, there will continue to be an increased risk that our future financial statements could contain errors that will be undetected. Further and continued determinations that there are material weaknesses in the effectiveness of our internal controls could reduce our ability to obtain financing or could increase the cost of any financing we obtain and require additional expenditures of resources to comply with applicable requirements.

We do not anticipate paying dividends on our common stock in the near 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 currently intend to retain any earnings for the future operation and development of our business, including exploration, development and acquisition activities or to retire outstanding debt. Therefore, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. Any future dividend payments will require approval by the board of directors. In addition, the terms of our credit agreement prohibit the payment of any dividends to the holders of our common stock.

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.

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 for resale by certain of our stockholders. Sales of these or other 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 14, 2020, there were 159,710,955 shares of our common stock issued and outstanding, excluding 5,871,991 shares of unvested restricted stock awarded under our 2019 Amended and Restated Stock Incentive Plan.

A change of control could limit our use of net operating losses to reduce future taxable income.

As of December 31, 2019, we had a net operating loss, or NOL, carryforward of approximately $1.3 billion for federal income tax purposes. If we were to experience an “ownership change,” as determined under Section 382 of the Internal

Revenue Code of 1986, as amended (or 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 for the month in which such ownership change occurs. 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 Code) at any time during a rolling three-year period.

Our business could be disrupted as a result of actions of certain stockholders.

During 2019, stockholders made public statements critical of our performance and advocated that we make certain changes regarding our strategic plan, capital allocation, executive compensation and corporate governance, including the addition of a stockholder representative to our board of directors. They have also suggested that they could pursue the nomination of director candidates for election to our board of directors at our 2020 Annual Meeting of Stockholders.

If any of our stockholders commence a proxy contest, further advocate for change or engage in other similar activities, then our business could be adversely affected. Responding to proxy contests and other actions by activist stockholders can be costly and time-consuming, disrupt our operations and divert the attention of our board of directors and senior management from the pursuit of business strategies, which could adversely affect our results of operations and financial condition. Additionally, perceived uncertainties as to our future direction as a result of stockholder activism or changes to the composition of the board of directors may lead to the perception of a change in the direction of the business, instability or lack of continuity, and, if individuals are elected to our board of directors with a specific agenda, the execution of our strategic plan may be disrupted or a new strategic plan altogether may be implemented. This may be exploited by our competitors, cause concern to our current or potential customers, and make it more difficult to attract and retain qualified personnel.

We cannot predict, and no assurances can be given, as to the outcome or timing of any matters relating to the foregoing actions by stockholders or the ultimate impact on our business, financial condition or results of operations. Further, any of these matters or any further actions by this or other stockholders may impact and result in volatility of the price of our common stock, including if this stockholder were to exit its investment in our common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is included in Item 1 and in the Supplemental Information on Oil and Gas Exploration and Production Activities in Note 19 of the notes to our consolidated financial statements included in this report.

ITEM 3. LEGAL PROCEEDINGS

Litigation and Regulatory Proceedings

We are involved in a number of litigation and regulatory proceedings that may result in material liabilities, including those described below. Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is indeterminate. Our total accrued liabilities in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different.

We, along with a number of other oil and gas companies, have been named as a defendant 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 (together, the "Complaints"). The Complaints allege that certain of the defendants' operations violated the State and Local Coastal Resources Management Act of

1978, as amended, and the rules, regulations, orders and ordinances adopted thereunder (the "CZM Laws") by causing substantial damage to land and waterbodies located in the coastal zone of the relevant Parish. 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 interest. The United States District Court for the Western District of Louisiana issued orders remanding the cases to their respective state court, and the defendants have appealed the remand orders to the 5th Circuit Court of Appeals.

In July 2019, Pigeon Land Company, Inc., a successor in interest to certain of our legacy Louisiana properties, filed an action against us and a number of other oil and gas companies in the 16th Judicial District Court for the Parish of Iberia in Louisiana. The suit alleges negligence, strict liability and various violations of Louisiana statutes relating to property damage in connection with the historic development of our Louisiana properties and seeks unspecified damages (including punitive damages), an injunction to return the affected property to its original condition, and the payment of reasonable attorney fees and legal expenses and interest.

In September 2019, a stockholder of Mammoth Energy filed a derivative action on behalf of Mammoth Energy against members of Mammoth Energy’s board of directors, including a director designated by us, and its significant stockholders, including us, in the United States District Court for the Western District of Oklahoma. In January 2020, plaintiffs consolidated actions against the same defendants in the United States District Court for the District of Delaware. The consolidated and amended complaint alleges, among other things, that we breached our fiduciary duties and misappropriated information as a controlling shareholder of Mammoth Energy in connection with Mammoth Energy’s activities in Puerto Rico following Hurricane Maria and our secondary offering of Mammoth Energy common stock in June 2018. The complaint seeks unspecified damages, the payment of reasonable attorney fees and legal expenses and interest and to force Mammoth Energy and its board of directors to make specified corporate governance reforms.

In October 2019, Saydee Resources, LLC, on behalf of itself and a class of similarly situated royalty holders, filed an action against us in the District Court of Grady County Oklahoma. The suit alleges that we underpaid royalty holders and seeks unspecified damages for breach of contract, tortious breach of contract, fraud and unjust enrichment.

In October 2019, Kelsie Wagner, in her capacity as trustee of various trusts and on behalf of the trusts and other similarly situated royalty owners, filed an action against us in the District Court of Grady County, Oklahoma. The suit alleges that we underpaid royalty owners and seeks unspecified damages for violations of the Oklahoma Production Revenue Standards Act and fraud.

SEC Investigation

The SEC has commenced an investigation with respect to certain actions by former Company management, including alleged improper personal use of Company assets, and potential violations by former management and the Company of the Sarbanes-Oxley Act of 2002 in connection with such actions. We have fully cooperated and intend to continue to cooperate fully with the SEC’s investigation. Although it is not possible to predict the ultimate resolution or financial liability with respect to this matter, we believe that the outcome of this matter will not have a material effect on our business, financial condition or results of operations.

Business Operations

We are involved in various lawsuits and disputes incidental to our business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions.

Environmental Contingencies

The nature of the oil and gas business carries with it certain environmental risks for us and our subsidiaries. We have implemented various policies, programs, procedures, training and audits to reduce and mitigate such environmental risks. We conduct periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and address the potential liability. Depending on the extent of an identified environmental concern, we may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition or agree to assume liability for the remediation of the property.

We received several Finding of Violation ("FOVs") from the United States Environmental Protection Agency ("USEPA") alleging violations of the Clean Air Act in Ohio. The first FOV for one site was dated December 11, 2013. Two subsequent FOVs incorporated and expanded the scope on January 4, 2017 and April 15, 2019. We entered into a settlement with the Department of Justice and USEPA agreeing to pay $1.7 million and invest in improvements at 17 well pads. The settlement was filed with the U.S. District Court for the Southern District of Ohio in January 2020, and is pending approval.

Other Matters

Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to our business operations are likely to have a material adverse effect on our future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

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

Common Stock

Our common stock trades on the Nasdaq Exchange under the symbol "GPOR".

Shareholders

At the close of business on February 14, 2020, there were approximately 313 stockholders and 15,722 beneficial owners of our common stock.

Unregistered Sales of Equity Securities and Use of Proceeds

In January 2019, our board of directors approved a new stock repurchase program to acquire up to $400.0 million of our outstanding common stock within a 24 month period. During the year ended December 31, 2019, we repurchased approximately 3.8 million shares of our outstanding common stock pursuant to the plan for total consideration of approximately $30.0 million. In the fourth quarter of 2019, the program was suspended but may be reactivated in the future depending on our projected leverage profile, commodity price outlook and market conditions. The Company did not repurchase any shares of our common stock during the quarter ended December 31, 2019 and has $370.0 million of shares that may yet be repurchased under its announced program.

Dividends

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

The following table sets forth selected consolidated financial data of Gulfport as of and for the years ended December 31, 2019, 2018, 2017, 2016 and 2015. The data are derived from our audited consolidated financial statements. The table below should be read in connection with *Management's Discussion and Analysis of Financial Condition and Results of Operations* and our consolidated financial statements and the related notes appearing elsewhere in Items 7 and 8, respectively, of this report.

	Fiscal Year Ended December 31,				
	2019	2018	2017	2016	2015
	(In thousands, except share data)				
Selected Consolidated Statements of Operations Data:					
Revenues	$ 1,346,008	$ 1,355,044	$ 1,320,303	$ 385,910	$ 708,990
Costs and expenses:					
Lease operating expenses	82,998	91,640	80,246	68,877	69,475
Production taxes	28,571	33,480	21,126	13,276	14,740
Midstream gathering and processing expenses	291,725	290,188	248,995	165,972	138,590
Depreciation, depletion and amortization	550,108	486,664	364,629	245,974	337,694
Impairment of oil and natural gas properties	2,039,770	—	—	715,495	1,440,418
General and administrative expenses	47,979	49,994	45,523	37,681	38,086
Restructuring costs	4,611	—	—	—	—
Accretion expense	3,939	4,119	1,611	1,057	820
Acquisition expense	—	—	2,392	—	—
	3,049,701	956,085	764,522	1,248,332	2,039,823
(Loss) Income from Operations	(1,703,693)	398,959	555,781	(862,422)	(1,330,833)
Other Expense (Income):					
Interest expense	141,786	141,912	115,613	69,258	55,102
Interest income	(801)	(314)	(1,009)	(1,230)	(643)
(Gain) loss on debt extinguishment	(48,630)	—	—	23,776	—
Gain on sale of equity method investments	—	(124,768)	(12,523)	(3,391)	—

Loss (income) from equity method investments, net	210,148	(49,904)	17,780	37,376	106,093
Other expense (income)	3,725	1,542	(1,041)	(5,589)	(10,500)
	306,228	(31,532)	118,820	120,200	150,052
(Loss) Income from Continuing Operations before Income Taxes	(2,009,921)	430,491	436,961	(982,622)	(1,480,885)
Income Tax (Benefit) Expense	(7,563)	(69)	1,809	(2,913)	(256,001)
(Loss) Income from Continuing Operations	(2,002,358)	430,560	435,152	(979,709)	(1,224,884)
Net (Loss) Income Available to Common Stockholders	$ (2,002,358)	$ 430,560	$ 435,152	$ (979,709)	$ (1,224,884)
Net (Loss) Income Per Common Share—Basic:	$ (12.49)	$ 2.46	$ 2.42	$ (7.97)	$ (12.27)
Net (Loss) Income Per Common Share—Diluted:	$ (12.49)	$ 2.45	$ 2.41	$ (7.97)	$ (12.27)

	At December 31,				
	2019	2018	2017	2016	2015
	(In thousands)				
Selected Consolidated Balance Sheet Data:					
Total assets	$ 3,882,819	$ 6,051,036	$ 5,807,752	$ 4,223,145	$ 3,334,734
Total debt, including current maturities	$ 1,978,651	$ 2,087,416	$ 2,038,943	$ 1,593,875	$ 946,263
Total liabilities	$ 2,568,227	$ 2,723,268	$ 2,706,138	$ 2,039,253	$ 1,295,897
Stockholders' equity	$ 1,314,592	$ 3,327,768	$ 3,101,614	$ 2,183,892	$ 2,038,837

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

The following discussion and analysis presents management's perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with "Item 8. Financial Statements and Supplementary Data" of this report. The following discussion and analysis generally discusses 2019 and 2018 items and year-to-year comparisons between 2019 and 2018. Discussions of 2017 items and year-to-year comparisons between 2018 and 2017 that are not included in this Form 10-K can be found in "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2018.

Overview

We are an independent natural gas-weighted exploration and production company focused on the exploration, acquisition and production of natural gas, crude oil and natural gas liquids ("NGL") in the United States with primary focus in the Appalachia and Mid-Continent basins. Our principal properties are located in Eastern Ohio targeting the Utica formation and in central Oklahoma targeting the SCOOP Woodford and SCOOP Springer formations.

2019 Highlights

- During the year ended December 31, 2019, we entered into several agreements to divest of certain non-core assets as part of our strategic initiatives to focus development in our core operating areas. These non-core divestitures consisted of the following:

    - We sold our non-core assets located in the West Cote Blanche Bay ("WCBB") and Hackberry fields of Louisiana for a purchase price of approximately $19.7 million, subject to customary closing terms and adjustments. We received approximately $9.2 million in cash and retained contingent overriding royalty interests. In addition, we could also receive contingent payments based on commodity prices exceeding specified thresholds over the two years following the closing date. The buyer assumed all plugging and abandonment liabilities associated with these assets, which totaled approximately $30.0 million at the divestiture date. The sale closed on July 3, 2019.

    - We sold certain non-operated interests in the Utica Shale for cash proceeds of $29.0 million subject to customary closing terms and adjustments. The sale closed on December 30, 2019.

    - We sold certain overriding royalty interests associated with assets we held in the Bakken for cash proceeds of approximately $7.0 million subject to customary closing terms and adjustments. The sale closed on December 11, 2019.

    - In December 2019, we entered into an agreement to divest our water infrastructure assets across our SCOOP position to a third-party water service provider. This transaction closed on January 2, 2020. We received $50.0 million in cash upon closing and have an opportunity to earn potential additional incentive payments over the next 15 years, subject to our ability to meet certain thresholds which will be driven by, among other things, our future development program and future water production levels. The agreement contains no minimum volume commitments. The assets related to this transaction are included in our amortization base of the full cost pool and we do not expect to recognize a gain or loss in our statement of operations.

- During the year ended December 31, 2019, we used borrowings under our revolving credit facility to repurchase in the open market approximately $190.1 million aggregate principal amount of our outstanding 6.625% Senior Notes due 2023 ("2023 Notes"), 6.000% Senior Notes due 2024 ("2024 Notes"), 6.375% Senior Notes due 2025 ("2025 Notes"), and 6.375% Senior Notes due 2026 ("2026 Notes") (collectively the "Notes"), for $138.8 million. We recognized a $48.6 million gain on debt extinguishment, which included retirement of unamortized issuance costs and fees associated with the repurchased debt.

- Production increased 1% to approximately 501,742 MMcfe for the year ended December 31, 2019 from approximately 496,505 MMcfe for the year ended December 31, 2018.

- During 2019, we spud 26 gross (23.2 net) wells, turned to sales 61 gross (54.1 net) operated wells, participated in an additional 47 gross (2.5 net) wells that were drilled by other operators on our Utica Shale and SCOOP acreage. Of our 26 new wells spud during 2019, 11 were completed as producing wells and, at year end, 14 were in various stages of completion and one was being drilled.

- During the year ended December 31, 2019, we reduced our unit lease operating expense by 10% to $0.17 per Mcfe from $0.18 per Mcfe during the year ended December 31, 2018.

- During the year ended December 31, 2019, we reduced our general and administrative expense by 4% to $48.0 million from $50.0 million during the year ended December 31, 2018.

Liquidity and Capital Resources

Overview. Historically, our primary sources of capital funding and liquidity have been our operating cash flow, borrowings under our revolving credit facility and issuances of equity and debt securities. Our ability to access these sources of funds can be significantly impacted by changes in capital markets, decreases in commodity prices and decreases in our production levels.

Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facility, we expect to be able to fund our planned capital expenditures, meet our debt service requirements and fund our other commitments and obligations for the next 12 months.

As of December 31, 2019, we had a cash balance of $6.1 million compared to $52.3 million as of December 31, 2018, and a net working capital deficit of $145.3 million as of December 31, 2019, compared to a net working capital deficit of $223.1 million as of December 31, 2018. As of December 31, 2019, our working capital deficit includes $0.6 million of debt due in the next 12 months. Our total principal debt as of December 31, 2019 was $2.0 billion compared to $2.1 billion as of December 31, 2018. As of December 31, 2019, we had $636.4 million of borrowing capacity available under the revolving credit facility, with outstanding borrowings of $120.0 million and $243.6 million utilized for various letters of credit. See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our debt obligations, including principal and carrying amounts of our notes.

Derivatives and Hedging Activities. Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Our natural gas, oil and NGL derivative activities, when combined with our sales of natural gas, oil and NGL, allow us to predict with greater certainty the total revenue we will receive.

As of December 31, 2019, we had the following open natural gas, oil and NGL derivative instruments:

Natural Gas Derivatives

Year	Type of Derivative Instrument	Index	Daily Volume (MMBtu/day)	Weighted Average Price
2020	Swaps	NYMEX Henry Hub	548,000	$ 2.88
2020	Basis Swaps	Various	70,000	$ (0.12)
2022	Sold Call Options	NYMEX Henry Hub	628,000	$ 2.90
2023	Sold Call Options	NYMEX Henry Hub	628,000	$ 2.90

Oil Derivatives

Year	Type of Derivative Instrument	Index	Daily Volume (Bbls/day)	Weighted Average Price
2020	Swaps	NYMEX WTI	6,000	$ 59.82

NGL Derivatives

Year	Type of Derivative Instrument	Index	Daily Volume (Bbls/day)	Weighted Average Price
2020	Swaps	Mont Belvieu C3	500	$ 21.63

See Note 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of derivatives and hedging activities.

Credit Facility. We have entered into a senior secured revolving credit facility agreement, 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, 2019, we had a borrowing base of $1.2 billion, with an elected commitment of $1.0 billion, and $120.0 million in borrowings outstanding under our revolving credit facility. Total funds available for borrowing, after giving effect to an aggregate of $243.6 million of letters of credit as of December 31, 2019, were $636.4 million. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries, excluding Grizzly Holdings Inc. ("Grizzly Holdings"), Mule Sky LLC ("Mule Sky") and GRUS, LLC ("GRUS"), guarantee our obligations under our revolving credit facility. Our next borrowing base redetermination is scheduled for the second quarter of 2020.

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 0.25% to 1.25%, 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 the administrative 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 1.25% to 2.25%, 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 administrative agent shall inquire as the “London Interbank Offered Rate” for deposits in U.S. dollars. As of December 31, 2019, amounts borrowed under our revolving credit facility bore interest at the weighted average rate of 3.30%.

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; agree to payment restrictions affecting our restricted subsidiaries; make investments; undertake fundamental changes including selling all or substantially all of our assets; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; enter into transactions with their affiliates; and engage in certain transactions with restricted subsidiaries. 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 (as defined under the revolving credit agreement) may not be greater than 4.00 to 1.00 for the twelve-month period of the end of each fiscal quarter; and (2) the ratio of EBITDAX to interest expense for the twelve-month period at the end of each fiscal quarter may not be less than 3.00 to 1.00. We were in compliance with these financial covenants at December 31, 2019.

Senior Notes. In April 2015, we issued an aggregate of $350.0 million in principal amount of our 2023 Notes. Interest on these senior 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. As of December 31, 2019, after giving effect to 2019 open market repurchases of these 2023 Notes, $329.5 million principal amount remained outstanding. The 2023 Notes will mature on May 1, 2023.

On October 14, 2016, we issued an aggregate of $650.0 million in principal amount of our 2024 Notes. Interest on the 2024 Notes accrues at a rate of 6.000% per annum on the outstanding principal amount thereof, payable semi-annually on April 15 and October 15 of each year. As of December 31, 2019, after giving effect to 2019 open market repurchases of these 2024 Notes, $603.4 million principal amount remained outstanding. The 2024 Notes will mature on October 15, 2024.

On December 21, 2016, we issued an aggregate of $600.0 million in principal amount of our 2025 Notes. Interest on the 2025 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof, payable semi-annually on May 15 and November 15 of each year. As of December 31, 2019, after giving effect to 2019 open market repurchases of these 2025 Notes, $529.5 million principal amount remained outstanding. The 2025 Notes will mature on May 15, 2025.

On October 11, 2017, we issued $450.0 million in aggregate principal amount of our 2026 Notes. Interest on the 2026 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof, payable semi-annually on January 15 and July 15 of each year. As of December 31, 2019, after giving effect to 2019 open market repurchases of these 2026 Notes, $397.5 million principal amount remained outstanding. The 2026 Notes will mature on January 15, 2026.

During the year ended December 31, 2019, we used borrowings under our revolving credit facility to repurchase in the open market approximately $190.1 million aggregate principal amount of our outstanding Notes for $138.8 million. This included approximately $20.5 million principal amount of the 2023 Notes, $46.6 million principal amount of the 2024 Notes, $70.5 million principal amount of the 2025 Notes, and $52.5 million principal amount of the 2026 Notes. We recognized a $48.6 million gain on debt extinguishment, which included retirement of unamortized issuance costs and fees associated with the repurchased debt.

We may use a combination of cash and borrowing under our revolving credit facility to retire our outstanding debt, through privately negotiated transactions, open market repurchases, redemptions, tender offers or otherwise, but we are under no obligation to do so.

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

If we experience a change of control (as defined in the senior note indentures relating to the Notes), we will be required to make an offer to repurchase the 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 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 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 Notes, certain of these covenants are subject to termination upon the occurrence of certain events, including in the event the Notes are ranked as "investment grade."

Construction Loan. On June 4, 2015, we entered into a construction loan agreement (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, after which date we began making monthly payments of interest and principal. The final payment is due June 4, 2025. As of December 31, 2019, the total borrowings under the construction loan were approximately $22.5 million.

Contractual and Commercial Obligations. The following table sets forth our contractual and commercial obligations atDecember 31, 2019:

Contractual Obligations	Payment due by period Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Long-term debt[(1)]:					
Principal	$ 2,002,402	$ 631	$ 121,357	$ 934,380	$ 946,034
Interest	613,260	118,428	236,198	203,330	55,304
Firm transportation contracts[(2)]	3,560,504	274,813	573,252	548,513	2,163,926
Operating lease liabilities[(3)]	57,438	35,045	22,275	118	—
Other	15,000	7,500	7,500	—	—
Total contractual cash obligations[(4)]	$ 6,248,604	$ 436,417	$ 960,582	$ 1,686,341	$ 3,165,264

(1) See Note 5 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our long-term debt.
(2) See Note 16 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our firm transportation contracts.
(3) See Note 9 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our operating lease liabilities.
(4) This table does not include derivative liabilities or the estimated discounted cost for future abandonment of oil and natural gas properties. See Notes 12 and 3 of the notes to our consolidated financial statements included in Item 8 of this report, respectively.

Off-balance Sheet Arrangements. We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2019, our material off-balance sheet arrangements and transactions include$243.6 million in letters of credit outstanding against our revolving credit facility and $105.1 million in surety bonds issued. Both the letters of credit and surety bonds are being used as financial assurance on certain firm transportation agreements. Management believes these items will expire without being funded. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. See Note 17 to our consolidated financial statements for further discussion of the various financial guarantees we have issued.

Capital Expenditures. Our capital commitments have been primarily for the execution of our drilling programs, share repurchases, and discounted repurchases of our senior notes. Our capital investment strategy is focused on prudently developing our existing properties in an effort to generate sustainable cash flow considering current and forecasted commodity prices while also selectively pursuing mergers or acquisitions in our current operating regions in an effort to gain scale and deepen our drilling inventory.

Our capital expenditures for 2020 are currently estimated to be in the range of$265.0 million to $285.0 million for drilling and completion expenditures. In addition, we currently expect to spend $20.0 million to $25.0 million in 2020 for non-drilling and completion expenditures, which includes acreage expenses, primarily lease extensions in the Utica Shale. The midpoint of the 2020 range of capital expenditures is 51% lower than the $602.5 million spent in 2019, primarily due to our decision to reduce capital activity in response to lower commodity prices, specifically natural gas prices, and our desire to fund our capital development program primarily with cash flow from operations. As a result of our decreased capital spending program for 2020 and the impact of our 2019 property divestitures, we expect our volumes in 2020 to be approximately 18% lower than 2019. Coupled with forecasted lower commodity prices, we expect 2020 revenues, operating cash flows and EBITDA to be lower in 2020 as compared to 2019.

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. We have the ability to react quickly to changing commodity prices and accelerate or decelerate our activity within our operating areas as market conditions warrant. Notwithstanding the foregoing, in the event commodity prices decline from current levels or our capital or other costs increase we may be required to obtain additional funds which we would seek to do through borrowings, offerings of debt or equity securities or other means, including the sale of assets. We regularly evaluate merger, acquisition and divestiture opportunities. Capital may not be available to us on acceptable terms or at all in the future. 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 2018, WTI prices ranged from $44.48 to $77.41 per barrel and the Henry Hub spot market price of natural gas ranged from $2.49 to $6.24 per MMBtu. During 2019, WTI prices ranged from $46.31 to $66.24 per barrel and the Henry Hub spot market price of natural gas ranged from $1.75 to $4.25 per MMBtu. If the prices of oil and natural gas 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 commodity prices and/or our reserves could also negatively impact the borrowing base under our revolving credit facility, which could limit our liquidity and ability to fund development activities.

See Item 7A. "Quantitative and Qualitative Disclosures about Market Risk" for information regarding our open fixed price swaps at December 31, 2019.

Cash Flow from Operating Activities. Net cash flow provided by operating activities was $724.0 million for the year ended December 31, 2019 as compared to $786.3 million for 2018. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 23% decrease in net revenues after giving effect to settled derivative instruments, partially offset by a decrease in our operating expenses.

Divestitures. During 2019, we divested certain non-core assets and interests in operated and non-operated oil and natural gas properties for approximately $48.5 million. Proceeds from these transactions were primarily used to repay debt and fund our development program. See Note 2 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Uses of Funds. The following table presents the uses of our cash and cash equivalents for the years ended December 31, 2019 and 2018:

	Years Ended December 31,			
	2019		2018	
	(In thousands)			
Oil and Natural Gas Property Expenditures:				
Drilling and completion costs		654,407		713,031
Leasehold acquisitions		39,664		125,585
Other		25,986		60,467
Total oil and natural gas property expenditures		720,057		899,083
Other Uses of Cash and Cash Equivalents				
Cash paid to repurchase senior notes		138,786		—
Cash paid to repurchase common stock		30,688		200,251
Additions to other property and equipment		5,021		7,870
Contributions to equity method investments		432		2,319
Other		288		831
Total other uses of cash and cash equivalents	$	175,215	$	211,271
Total uses of cash and cash equivalents	$	895,272	$	1,110,354

Drilling and Completion Costs. During 2019, we spud 16 gross (14.6 net) and commenced sales from 47 gross (41.6 net) wells in the Utica Shale for a total cost of approximately $318.3 million. In addition, five gross (0.9 net) wells were spud and 14 gross (3.3 net) wells were turned to sales by other operators on our Utica Shale acreage during 2019 for a total cost to us of approximately $44.2 million.

During 2019, we spud 10 gross (8.6 net) and commenced sales from 14 gross (12.6 net) wells in the SCOOP for a total cost of approximately $124.8 million. In addition, 42 gross (1.6 net) wells were spud and 39 gross (1.2 net) wells were turned to sales by other operators on our SCOOP acreage during 2019 for a total cost to us of approximately $14.6 million.

Results of Operations

The markets for oil and natural gas have historically been, and will likely 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:

	Years Ended December 31,	
	2019	2018
	(In thousands, unless otherwise stated)	
Natural gas sales		
Natural gas production volumes (MMcf)	458,178	443,742
Total natural gas sales	$ 918,263	$ 1,121,815
Natural gas sales without the impact of derivatives ($/Mcf)	$ 2.00	$ 2.53
Impact from settled derivatives ($/Mcf)	$ 0.23	$ (0.04)
Average natural gas sales price, including settled derivatives ($/Mcf)	$ 2.23	$ 2.49
Oil and condensate sales		
Oil and condensate production volumes (Mbbls)	2,186	2,801
Total oil and condensate sales	$ 117,937	$ 177,793
Oil and condensate sales without the impact of derivatives ($/Bbl)	$ 53.95	$ 63.48
Impact from settled derivatives ($/Bbl)	$ 1.86	$ (9.51)
Average oil and condensate sales price, including settled derivatives ($/Bbl)	$ 55.81	$ 53.97
NGL sales		
NGL production volumes (MGal)	213,129	251,720
Total NGL sales	$ 101,448	$ 178,915
NGL sales without the impact of derivatives ($/Gal)	$ 0.48	$ 0.71
Impact from settled derivatives ($/Gal)	$ 0.06	$ (0.05)
Average NGL price, including settled derivatives ($/Gal)	$ 0.54	$ 0.66
Natural gas, oil and condensate and NGL sales		
Natural gas equivalents (MMcfe)	501,742	496,505
Total natural gas, oil and condensate and NGL sales	$ 1,137,648	$ 1,478,523
Natural gas, oil and condensate and NGL sales without the impact of derivatives ($/Mcfe)	$ 2.27	$ 2.98
Impact from settled derivatives ($/Mcfe)	$ 0.24	$ (0.12)
Average natural gas, oil and condensate and NGL sales price, including settled derivatives ($/Mcfe)	$ 2.51	$ 2.86
Production Costs:		
Average production costs ($/Mcfe)	$ 0.17	$ 0.18
Average production taxes ($/Mcfe)	$ 0.06	$ 0.07
Average midstream gathering and processing ($/Mcfe)	$ 0.58	$ 0.58
Total production costs, midstream costs and production taxes ($/Mcfe)	$ 0.81	$ 0.83

The total natural gas, oil and NGL volumes hedged for 2019 and 2018 represented approximately 96% and 78%, respectively, of our total sales volumes for the applicable year.

From 2018 to 2019, our net equivalent gas production increased 1% from 1,360 MMcfe per day to 1,375 MMcfe per day primarily as a result of our continued development of our Utica Shale and SCOOP acreage. We currently estimate that our 2020 production will be between 1,100 and 1,150 MMcfe per day. 2020 production levels are expected to be lower than 2019 levels as we have decided to reduce our 2020 capital spending as compared to 2019 levels given relatively low natural gas prices. 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, 2019 and December 31, 2018

We reported net loss of $2.0 billion for the year ended December 31, 2019 as compared to net income of $430.6 million for the year ended December 31, 2018. This decrease in period-to-period net income was due primarily to a $2.0 billion oil and natural gas properties impairment charge related primarily to the decline in commodity prices, a $260.1 million decrease in income from equity method investments, a $124.8 million decrease in gain on sale of equity method investments, a $63.4 million increase in depreciation, depletion and amortization expense, and a $9.0 million decrease in natural gas, oil and NGL revenues, partially offset by a $48.6 million increase in gain on debt extinguishment, an $8.6 million decrease in lease operating expenses, a $4.9 million decrease in production taxes, and a $2.0 million decrease in general and administrative expenses for the year ended December 31, 2019, as compared to the year ended December 31, 2018.

Natural Gas, Oil and NGL Sales

	Years Ended December 31,		
	2019	2018	change
	($ In thousands)		
Natural gas	918,263	1,121,815	(18)%
Oil and condensate	117,937	177,793	(34)%
NGL	101,448	178,915	(43)%
Natural gas, oil and NGL revenues	$ 1,137,648	$ 1,478,523	(23)%

The decrease in natural gas sales without the impact of derivatives was primarily due to a 21% decrease in natural gas market prices, partially offset by a 3% increase in natural gas sales volumes.

The decrease in oil and condensate sales without the impact of derivatives was due to a 22% decrease in oil and condensate sales volumes and a 15% decrease in oil and condensate market prices.

The decrease in NGL sales without the impact of derivatives was due to a 33% decrease in NGL market prices and a 15% decrease in NGL sales volumes.

Natural Gas, Oil and NGL Derivatives

	Years Ended December 31,	
	2019	2018
	($ In thousands)	
Natural gas derivatives - fair value (gains) losses	$ (89,576)	$ 98,130
Natural gas derivatives - settlement (gains) losses	(104,874)	18,000
Total (gains) losses on natural gas derivatives	(194,450)	116,130
Oil and condensate derivatives - fair value (gains) losses	(2,952)	(13,546)
Oil and condensate derivatives - settlement (gains) losses	(4,083)	26,630
Total (gains) losses on oil and condensate derivatives	(7,035)	13,084
NGL derivatives - fair value (gains) losses	7,541	(19,533)
NGL derivatives - settlement (gains) losses	(14,173)	13,798
Total (gains) losses on NGL derivatives	(6,632)	(5,735)
Contingent consideration arrangement - fair value gains	(243)	—
Total (gains) losses on natural gas, oil and NGL derivatives	$ (208,360)	$ 123,479

See Note 12 to our consolidated financial statements for further discussion of our derivative activity.

Lease Operating Expenses

	Years Ended December 31,		
	2019	2018	change
	($ In thousands, except per unit)		
Lease operating expenses			
Utica	$ 55,839	$ 54,347	3 %
SCOOP	18,239	18,385	(1)%
WCBB	6,941	14,178	(51)%
Hackberry	1,679	4,435	(62)%
Other(1)	300	295	2 %
Total lease operating expenses	$ 82,998	$ 91,640	(9)%
Lease operating expenses per Mcfe			
Utica	$ 0.14	$ 0.14	2 %
SCOOP	0.18	0.20	(6)%
WCBB	4.87	3.87	26 %
Hackberry	7.65	6.57	16 %
Other(1)	0.79	0.60	32 %
Total lease operating expenses per Mcfe	$ 0.17	$ 0.18	(10)%

(1) Includes Niobrara and Bakken

The decrease in total and per unit lease operating expenses ("LOE"), not including production taxes, in 2019 was mainly the result of our divesting of our Louisiana properties which have higher operating costs than our Utica and SCOOP areas.

Production Taxes

	Years Ended December 31,		
	2019	2018	change
	($ In thousands, except per unit)		
Production taxes	$ 28,571	$ 33,480	(15)%
Production taxes per Mcfe	$ 0.06	$ 0.07	(16)%

The decrease in production taxes was primarily related to a decrease in realized prices in 2019 as compared to 2018.

Midstream Gathering and Processing Expenses

	Years Ended December 31,		
	2019	2018	change
	($ In thousands, except per unit)		
Midstream gathering and processing expenses	$ 291,725	$ 290,188	1 %
Midstream gathering and processing expenses per Mcfe	$ 0.58	$ 0.58	(1)%

Midstream gathering and processing expenses were relatively consistent in 2019 as compared to 2018 on both a total expense basis and a per unit basis.

Depreciation, Depletion and Amortization

	Years Ended December 31,		
	2019	2018	change
	($ In thousands, except per unit)		
Depreciation, depletion and amortization	$ 550,108	$ 486,664	13 %
Depreciation, depletion and amortization per Mcfe	$ 1.10	$ 0.98	12 %

Depreciation, depletion and amortization ("DD&A") expense consisted of $538.9 million in depletion of oil and natural gas properties and $11.2 million in depreciation of other property and equipment in 2019, compared to $476.4 million in depletion of oil and natural gas properties and $10.3 million in depreciation of other property and equipment in 2018. The increase in DD&A was due to an increase in our amount of oil and gas properties subject to amortization and a decrease in our total proved reserves volume used to calculate our total DD&A expense.

Impairment of Oil and Gas Properties. During the year ended December 31, 2019, we had a $2.0 billion oil and natural gas properties impairment charge related primarily to the decline in commodity prices, compared to no impairment charge of oil and gas properties in 2018. If prices of natural gas, oil and NGL continue to decline, the Company may be required to further write down the value of its oil and natural gas properties, which could negatively affect its results of operations.

Equity Investments

	Years Ended December 31,		
	2019	2018	change
	($ In thousands, except per unit)		
Gain on sale of equity method investments	$ —	$ (124,768)	(100)%
Loss (income) from equity method investments, net	$ 210,148	$ (49,904)	(521)%

Gain on sale of equity method investments during the year ended December 31, 2018 consisted of $96.4 million from the sale of our interest in Strike Force and $28.3 million from the sale of Mammoth Energy common stock. The decrease in income from equity method investments is primarily related to a $160.8 million impairment loss related to our investment in

Mammoth Energy and a $32.4 million impairment loss related to our investment in Grizzly for the year ended December 31, 2019. See Note 4 to our consolidated financial statements for further discussion on our equity investments.

General and Administrative Expenses

	Years Ended December 31,		
	2019	2018	change
	($ In thousands, except per unit)		
General and administrative expenses, gross	$ 89,291	$ 97,526	(8)%
Reimbursed from third parties	(11,173)	(9,820)	14 %
Capitalized general and administrative expenses	(30,139)	(37,712)	(20)%
General and administrative expenses, net	$ 47,979	$ 49,994	(4)%
General and administrative expenses, net per Mcfe	$ 0.10	$ 0.10	(5)%

The decrease in total general and administrative expenses, net was due primarily to lower compensation and benefits and cost-focused initiatives.

Restructuring Costs. In the fourth quarter of 2019, we announced and completed a workforce reduction representing approximately 13% of our headcount. In connection with the reduction, we incurred a total charge of approximately $4.6 million, primarily consisting of one-time employee-related termination benefits, with a remaining liability of $0.2 million at December 31, 2019.

Accretion Expense. Accretion expense decreased to $3.9 million for the year ended December 31, 2019 from $4.1 million for the year ended December 31, 2018, primarily as a result of a decrease in our asset retirement obligation due to the sale of our Louisiana properties.

Interest Expense

	Years Ended December 31,	
	2019	2018
	($ In thousands, except per unit)	
Interest expense on senior notes	125,687	129,125
Interest expense on revolving credit agreement	12,088	9,601
Interest expense on construction loan and other	1,055	1,535
Capitalized interest	(3,372)	(4,470)
Amortization of loan costs	6,328	6,121
Total interest expense	$ 141,786	$ 141,912
Interest expense per Mcfe	$ 0.28	$ 0.29
Weighted average debt outstanding under revolving credit facility	$ 161,416	$ 83,589

Interest expense was relatively consistent in 2019 as compared to 2018 on both a total expense basis and a per unit basis. Total weighted debt outstanding under our revolving credit facility was $161.4 million for the year ended December 31, 2019 as compared to $83.6 million outstanding under such facility for 2018; however, this increase was largely offset by decreases in interest on our senior notes outstanding for 2019 as compared to 2018 due to senior notes repurchases.

Income Taxes. We recognized an income tax benefit of $7.6 million million in 2019 compared to an income tax benefit of $69 thousand in 2018. The income tax benefit for 2019 consists mainly of a partial release of valuation allowance that was maintained against our Oklahoma deferred tax asset, as the Company believes that it can utilize a portion of its Oklahoma state NOL through carrybacks and carryforwards to offset Oklahoma sourced income from the sale of assets.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States require us to make estimates and assumptions. The accounting estimates and assumptions we consider to be most significant to our financial statements are discussed below. Our management has discussed each critical accounting estimate with the Audit Committee of our Board of Directors.

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.

Under the full cost method, capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly.

We review the carrying value of our oil and natural gas properties under the full cost method of accounting prescribed by the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test.

Two primary factors impacting this test are reserve estimates and the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2019. Downward revisions to estimates of oil and natural gas reserves and/or unfavorable prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. During the year ended December 31, 2019 we recorded impairments of our oil and natural gas properties in the amount of $2.0 billion. No such impairments were required for the year ended December 31, 2018. See Oil and Natural Gas Properties in Note 1 of the notes to our consolidated financial statements included in Item 8 of this report for further information on the full cost method of accounting.

Oil, Natural Gas and NGL Reserves. Estimates of oil and natural gas reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in natural gas, oil or NGL prices could result in actual results differing significantly from our estimates. See Note 19 included in Item 8 of this report for further information.

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. Quarterly, 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, 2019, a valuation allowance of $647.6 million had been established for the net deferred tax asset.

Revenue Recognition. We derive almost all of our revenue from the sale of natural gas, crude oil and NGL 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 received 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 currently account for our investments in Mammoth Energy Services, Inc. ("Mammoth Energy") and Grizzly Oil Sands ULC ("Grizzly") using the equity method.

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 charge.

Derivative Instruments. We seek to reduce our exposure to unfavorable changes in natural gas, oil and NGL 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. All derivative instruments are 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. 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 7A. "*Natural Gas, Oil and NGL Derivatives*" for a summary of our derivative instruments in place as ofDecember 31, 2019.

Disclosures About Effects of Transactions with Related parties

Our equity method investees are considered related parties. See Notes 4, 9 and 15 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of transactions with our equity method investees.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Natural Gas, Oil and Natural Gas Liquids Derivative Instruments. Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of our exposure to adverse price changes, we have entered into various derivative instruments. Our natural gas, oil and NGL derivative activities, when combined with our sales of natural gas, oil and NGL, allow us to predict with greater certainty the revenue we will receive. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for protecting short-term cash flow and attempting to mitigate exposure to adverse natural gas, oil and NGL price changes is to hedge into strengthening natural gas, oil and NGL futures markets when prices reach levels that management believes are unsustainable for the long term, have material downside risk in the short term or provide reasonable rates of return on our invested capital. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas trends, oil and natural gas storage inventory levels, industry decline rates for base production and weather trends. Executive management is involved in all risk management activities and the Board of Directors reviews our derivative program at its quarterly board meetings. We believe we have sufficient internal controls to prevent unauthorized trading.

We use derivative instruments to achieve our risk management objectives, including swaps and options. All of these are described in more detail below. We typically use swaps for a large portion of the oil and natural gas price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility.

We determine the notional volume potentially subject to derivative contracts by reviewing our overall estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of likely production from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not enter into derivative contracts for volumes in excess of our share of forecasted production, and if production estimates were lowered for future periods and derivative instruments are already executed for some volume above the new production forecasts, the positions would be reversed. The actual fixed price on our derivative instruments is derived from the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow

NYMEX futures. All of our commodity derivative instruments are net settled based on the difference between the fixed price as stated in the contract and the floating-price, resulting in a net amount due to or from the counterparty.

We review our derivative positions continuously and if future market conditions change and prices are at levels we believe could jeopardize the effectiveness of a position, we will mitigate this risk by either negotiating a cash settlement with our counterparty, restructuring the position or entering into a new trade that effectively reverses the current position. The factors we consider in closing or restructuring a position before the settlement date are identical to those we review when deciding to enter into the original derivative position. Gains or losses related to closed positions will be recognized in the month specified in the original contract.

We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to counterparty valuations for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been partially mitigated under our commodity hedging arrangements that require counterparties to post collateral if their obligations to us are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. See Note 12 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the fair value measurements associated with our derivatives.

As of December 31, 2019, our natural gas, oil and NGL derivative instruments consistent of the following types of instruments:

- *Swaps*: We receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. In exchange for higher fixed prices on certain of our swap trades, we may sell call options.

- *Basis Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. We receive the fixed price differential and pay the floating market price differential to the counterparty for the hedged commodity.

- *Options*: We sell, and occasionally buy, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the counterparty the excess on sold call options, and we receive the excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.

As of December 31, 2019, we had the following open natural gas, oil and NGL derivative instruments:

	Volume	Weighted Average Price: Fixed	Weighted Average Price: Call	Weighted Average Price: Differential	Fair Value Asset (Liability)
	MMBtu/day	$/MMBtu			(in thousands)
Natural Gas:					
Swaps:					
Short-term	548,000	$ 2.88	$ —	$ —	$ 121,934
Call Options (sold)[1]:					
Long-term	628,000	$ —	$ 2.90	$ —	$ (53,135)
Basis Swaps:					
Short-term	70,000	$ —	$ —	$ (0.12)	$ (267)
Total Natural Gas					$ 68,532
	Bbls/day	$/Bbl			
Oil:					
Swaps:					
Short-term	6,000	$ 59.82	$ —	$ —	$ 2,952
Total Oil					$ 2,952
	Bbls/day	$/Bbl			
NGL:					
Swaps:					
Short-term	500	$ 21.63	$ —	$ —	$ 461
Total NGL					$ 461
Total Commodities					$ 71,945
Contingent Consideration:					
Louisiana Divestiture[2]:					
Short-term					$ 818
Long-term					$ 563
Total					$ 1,381
Total Derivative Asset					$ 73,326

(1) In the third quarter of 2019, we sold call options in exchange for a premium, and used the associated premiums received to enhance the fixed price for a portion of the fixed price natural gas swaps primarily for 2020 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.

(2) The purchase and sale agreement for the sale of our non-core assets located in the WCBB and Hackberry fields of Louisiana included a contingent consideration arrangement that entitles us to receive bonus payments if commodity prices exceed specified thresholds. The calculated fair value of this contingent payment arrangement was approximately $1.1 million as of the closing date of the divestiture.

In January and February 2020, we early terminated certain fixed price swaps for natural gas scheduled to settle in August through November of 2020 covering an average of approximately 294,000 MMBtu of natural gas per day over this four month period. The value received from these early terminations was used to enhance the fixed price for new natural gas swaps for April and May of 2020 covering an average of approximately 472,000 MMBtu of natural gas per day over this two month period at a weighted average price of $2.85 per MMBtu. Our fixed price swap contracts are tied to the commodity prices on NYMEX Henry Hub for natural gas and Mont Belvieu for propane, pentane and ethane. We will receive the fixed priced amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX Henry Hub for natural gas or Mont Belvieu for propane, pentane and ethane.

At February 27, 2020, we have hedged approximately 49% to 52% of our expected 2020 production under our 2020 contracts. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or commodities prices increase. At December 31, 2019, we had a net asset derivative position of $73.3 million as compared to a net liability derivative position of $13.0 million as of December 31, 2018, 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 $99.8 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $85.5 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.

Interest Rate Risk. 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 United States or, if the eurodollar rates are elected, the eurodollar rates. At December 31, 2019, we had $120.0 million in borrowings outstanding under our credit facility which bore interest at the weighted average rate of 3.30%. A 1% increase in the average interest rate would have increased interest expense by approximately $1.2 million based on outstanding borrowings under our revolving credit facility at December 31, 2019. As of December 31, 2019, we did not have any interest rate swaps to hedge our interest risks.

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, 2019 and 2018, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 27, 2020 expressed an adverse 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 included 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.

Change in accounting principle
As discussed in Note 9 to the consolidated financial statements, the Company has adopted new accounting guidance as of January 1, 2019, related to the adoption of Accounting Standards Codification Topic 842, *Leases*. Our opinion is not modified with respect to this matter.

Critical audit matters
The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Depletion expense and impairment of oil and gas properties impacted by the Company's estimation of proved reserves

As described further in Note 1 to the financial statements, the Company uses the full cost method of accounting for oil and gas operations. This accounting method requires management to make estimates of proved reserves and related future net cash flows to compute and record depletion, depreciation and amortization, as well as to assess potential impairment of oil and gas properties (the full cost ceiling test). To estimate the volume of proved oil and gas reserve quantities, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with those proved reserves to determine if wells are expected to be economical under the appropriate pricing assumptions that are required in the estimation of depletion, depreciation and amortization expense and potential ceiling test impairment assessments. We identified the estimation of proved reserves as it relates to the recognition of depletion, depreciation and amortization expense and the assessment of potential impairment as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that relatively minor changes in certain inputs and assumptions that are necessary to estimate the volume and future cash flows of the Company's proved reserves could have a significant impact on the measurement of depletion, depreciation and amortization expense and/or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others.

- We tested the design and operating effectiveness of internal controls relating to management's estimation of proved reserves for the purpose of estimating depletion, depreciation and amortization expense and assessing the Company's oil and gas properties for potential ceiling test impairment.

- We evaluated the independence, objectivity, and professional qualifications of the Company's reserve specialists, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company's proved reserve volumes and read the report prepared by the Company's reserve specialists.

- We evaluated sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions that are derived from the Company's accounting records, such as historical pricing differentials, operating costs, estimated capital costs, and ownership interests. We tested management's process for determining the assumptions, including examining the underlying support, on a sample basis where applicable. Specifically, our audit procedures involved testing management's assumptions as follows:

    - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for pricing differentials, where applicable;
    - Tested the model used to estimate the operating costs at year end and compared to historical operating costs;
    - Tested the model used to determine the future capital expenditures and compared estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells, where applicable;
    - Tested the working and net revenue interests used in the reserve report by inspecting land and division order records;
    - Evaluated the Company's evidence supporting the proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties; and
    - Applied analytical procedures to the reserve report by comparing to historical actual results and to the prior year's reserve report.

Valuation Allowance of Deferred Tax Assessment

As described further in Note 1 and 10 to the financial statements, the Company records a valuation allowance to reduce total net deferred tax assets when a judgment is made that is considered more likely than not that a tax benefit will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences will become deductible. The Company assesses the need for a valuation allowance by evaluating both positive and negative evidence that may exist. We identified the realizability of deferred tax assets as a critical audit matter.

The principal considerations for our determination that the realizability of deferred tax assets is a critical audit matter are that (a) the forecast of future taxable income is an accounting estimate subject to a high level of estimation and (b) the determination of any limitations on the utilization of net operating loss carryforwards involves complex calculations and judgment. There is inherent uncertainty and subjectivity related to management's judgments and assumptions regarding the Company's future taxable income, which are complex in nature and require significant auditor judgment.

Our audit procedures related to the valuation of deferred taxes included the following, among others.

- We tested the effectiveness of controls over management's estimates of the realization of the deferred tax assets, including those over management's corporate model which was the basis for the forecast of future taxable income, management's tax planning strategies and the determination of whether it is more likely than not that the deferred tax assets will be realized prior to expiration.

- With the assistance of our income tax specialists, we evaluated the forecast of future taxable income considering whether the estimated future sources of taxable income were of the appropriate character to utilize the net operating loss carryforwards and other temporary differences giving rise to the deferred tax assets under current tax law.

- With the assistance of our income tax specialists, we evaluated management's Internal Revenue Code Section 382 ownership change calculations.

- We tested the reasonableness of management's corporate model used to estimate future taxable income by comparing the estimates to the following:

    - Historical taxable income.
    - Internal communications with the board of directors.
    - Evidence obtained in other areas of the audit.
    - Management's history of carrying out its stated plans and its ability to carry out its plans considering contractual commitments, available financing, or debt covenants.

/s/ GRANT THORNTON LLP

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

Oklahoma City, Oklahoma
February 27, 2020

GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2019	December 31, 2018
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 6,060	$ 52,297
Accounts receivable—oil and natural gas sales	121,210	210,200
Accounts receivable—joint interest and other	47,975	22,497
Prepaid expenses and other current assets	4,431	10,017
Short-term derivative instruments	126,201	21,352
Total current assets	305,877	316,363
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $1,686,666 and $2,873,037 excluded from amortization in 2019 and 2018, respectively	10,595,735	10,026,836
Other property and equipment	96,719	92,667
Accumulated depletion, depreciation, amortization and impairment	(7,228,660)	(4,640,098)
Property and equipment, net	3,463,794	5,479,405
Other assets:		
Equity investments	32,044	236,121
Long-term derivative instruments	563	—
Deferred tax asset	7,563	—
Inventories	5,182	5,344
Operating lease assets	14,168	—
Operating lease assets - related parties	43,270	—
Other assets	10,358	13,803
Total other assets	113,148	255,268
Total assets	$ 3,882,819	$ 6,051,036
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 415,218	$ 518,380
Short-term derivative instruments	303	20,401
Current portion of operating lease liabilities	13,826	—
Current portion of operating lease liabilities - related parties	21,220	—
Current maturities of long-term debt	631	651
Total current liabilities	451,198	539,432
Long-term derivative instruments	53,135	13,992
Asset retirement obligation—long-term	60,355	79,952
Uncertain tax position liability	3,127	3,127
Non-current operating lease liabilities	342	—
Non-current operating lease liabilities - related parties	22,050	—
Long-term debt, net of current maturities	1,978,020	2,086,765
Total liabilities	2,568,227	2,723,268
Commitments and contingencies (Notes 16 and 17)		
Preferred stock, $.01 par value; 5,000,000 authorized (30,000 authorized as redeemable 12% cumulative preferred stock, Series A), and none issued and outstanding	—	—
Stockholders' equity:		
Common stock - $.01 par value, 200,000,000 shares authorized, 159,710,955 issued and outstanding in 2019 and 162,986,045 in 2018	1,597	1,630
Paid-in capital	4,207,554	4,227,532
Accumulated other comprehensive loss	(46,833)	(56,026)
Accumulated deficit	(2,847,726)	(845,368)
Total stockholders' equity	1,314,592	3,327,768
Total liabilities and stockholders' equity	$ 3,882,819	$ 6,051,036

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
	2019	2018	2017
	(In thousands, except share data)		
Revenues:			
Natural gas sales	$ 918,263	$ 1,121,815	$ 845,999
Oil and condensate sales	117,937	177,793	124,568
Natural gas liquid sales	101,448	178,915	136,057
Net gain (loss) on natural gas, oil, and NGL derivatives	208,360	(123,479)	213,679
	1,346,008	1,355,044	1,320,303
Costs and expenses:			
Lease operating expenses	82,998	91,640	80,246
Production taxes	28,571	33,480	21,126
Midstream gathering and processing expenses	291,725	290,188	248,995
Depreciation, depletion and amortization	550,108	486,664	364,629
Impairment of oil and natural gas properties	2,039,770	—	—
General and administrative expenses	47,979	49,994	45,523
Restructuring costs	4,611	—	—
Accretion expense	3,939	4,119	1,611
Acquisition expense	—	—	2,392
	3,049,701	956,085	764,522
(LOSS) INCOME FROM OPERATIONS	(1,703,693)	398,959	555,781
OTHER EXPENSE (INCOME):			
Interest expense	141,786	141,912	115,613
Interest income	(801)	(314)	(1,009)
Gain on debt extinguishment	(48,630)	—	—
Gain on sale of equity method investments	—	(124,768)	(12,523)
Loss (income) from equity method investments, net	210,148	(49,904)	17,780
Other expense (income), net	3,725	1,542	(1,041)
	306,228	(31,532)	118,820
(LOSS) INCOME BEFORE INCOME TAXES	(2,009,921)	430,491	436,961
INCOME TAX (BENEFIT) EXPENSE	(7,563)	(69)	1,809
NET (LOSS) INCOME	$ (2,002,358)	$ 430,560	$ 435,152
NET (LOSS) INCOME PER COMMON SHARE:			
Basic	$ (12.49)	$ 2.46	$ 2.42
Diluted	$ (12.49)	$ 2.45	$ 2.41
Weighted average common shares outstanding—Basic	160,341,125	174,675,840	179,834,146
Weighted average common shares outstanding—Diluted	160,341,125	175,398,706	180,253,024

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

	For the Year Ended December 31,		
	2019	2018	2017
	(In thousands)		
Net (loss) income	$ (2,002,358)	$ 430,560	$ 435,152
Foreign currency translation adjustment[1]	9,193	(15,487)	12,519
Other comprehensive income (loss)	9,193	(15,487)	12,519
Comprehensive (loss) income	$ (1,993,165)	$ 415,073	$ 447,671

(1) No taxes were recorded for the years endedDecember 31, 2019, 2018 and 2017.

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Paid-in	Accumulated Other Comprehensive	Accumulated	Total Stockholders'
	Shares	Amount	Capital	Loss	Deficit	Equity
			(In thousands, except share data)			
Balance at January 1, 2017	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-based 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
Net Income	—	—	—	—	430,560	430,560
Other Comprehensive Loss	—	—	—	(15,487)	—	(15,487)
Stock-based Compensation	—	—	11,332	—	—	11,332
Shares Repurchased	(20,746,536)	(207)	(200,044)	—	—	(200,251)
Issuance of Restricted Stock	626,671	6	(6)	—	—	—
Balance at December 31, 2018	162,986,045	1,630	4,227,532	(56,026)	(845,368)	3,327,768
Net Loss	—	—	—	—	(2,002,358)	(2,002,358)
Other Comprehensive Income	—	—	—	9,193	—	9,193
Stock-based Compensation	—	—	10,677	—	—	10,677
Shares Repurchased	(3,951,198)	(40)	(30,648)	—	—	(30,688)
Issuance of Restricted Stock	676,108	7	(7)	—	—	—
Balance at December 31, 2019	159,710,955	$ 1,597	$ 4,207,554	$ (46,833)	$ (2,847,726)	$ 1,314,592

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2019	2018	2017
	(In thousands)		
Cash flows from operating activities:			
Net (loss) income	$ (2,002,358)	$ 430,560	$ 435,152
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Accretion expense	3,939	4,119	1,611
Depletion, depreciation and amortization	550,108	486,664	364,629
Impairment of oil and natural gas properties	2,039,770	—	—
Stock-based compensation expense	4,911	6,799	6,369
Loss (income) from equity investments, net	210,289	(49,625)	18,513
Gain on debt extinguishment	(48,630)	—	—
Change in fair value of derivative instruments	(85,230)	65,051	(188,802)
Deferred income tax (benefit) expense	(7,563)	1,208	1,690
Amortization of loan costs	6,328	6,121	5,011
Gain on sale of equity method investments and other assets	(220)	(124,768)	(12,523)
Distributions from equity method investments	2,457	3,206	—
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable—oil and natural gas sales	88,990	(63,427)	(35,879)
(Increase) decrease in accounts receivable—joint interest and other	(25,478)	12,943	(9,573)
Decrease in accounts receivable—related parties	—	—	16
Decrease (increase) in prepaid expenses and other current assets	5,586	(5,695)	(1,777)
Decrease (increase) in other assets	915	4,066	(7,866)
(Decrease) increase in accounts payable, accrued liabilities and other	(19,548)	9,768	106,375
Settlement of asset retirement obligation	(273)	(719)	(3,057)
Net cash provided by operating activities	723,993	786,271	679,889
Cash flows from investing activities:			
Deductions to cash held in escrow	—	—	8
Additions to other property and equipment	(5,021)	(7,870)	(19,372)
Acquisitions of oil and natural gas properties	—	—	(1,348,657)
Additions to oil and natural gas properties	(720,057)	(899,083)	(1,064,678)
Proceeds from sale of oil and gas properties	48,527	5,114	4,866
Proceeds from sale of other property and equipment	267	351	1,569
Proceeds from sale of equity method investments	—	226,487	—
Contributions to equity method investments	(432)	(2,319)	(55,280)
Distributions from equity method investments	1,945	446	7,376
Net cash used in investing activities	(674,771)	(676,874)	(2,474,168)
Cash flows from financing activities:			
Principal payments on borrowings	(877,697)	(220,575)	(365,276)
Borrowings on line of credit	952,000	265,000	365,000
Proceeds from bond issuance	—	—	450,000
Repurchase of senior notes	(138,786)	—	—
Borrowings on term loan	—	—	2,951
Debt issuance costs and loan commitment fees	(288)	(831)	(14,350)
Payments on repurchase of stock	(30,688)	(200,251)	—
Proceeds from issuance of common stock, net of offering costs and exercise of stock options	—	—	(5,364)
Net cash (used in) provided by financing activities	(95,459)	(156,657)	432,961
Net decrease in cash, cash equivalents and restricted cash	(46,237)	(47,260)	(1,361,318)
Cash, cash equivalents and restricted cash at beginning of period	52,297	99,557	1,460,875
Cash, cash equivalents and restricted cash at end of period	$ 6,060	$ 52,297	$ 99,557

(Continued on next page)

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Supplemental disclosure of cash flow information:						
Interest payments	$	142,664	$	132,995	$	107,548
Income tax receipts	$	(1,794)	$	—	$	(1,105)
Supplemental disclosure of non-cash transactions:						
Capitalized stock-based compensation	$	5,766	$	4,533	$	4,246
Asset retirement obligation capitalized	$	6,883	$	1,452	$	42,270
Asset retirement obligation removed due to divestiture	$	(30,146)	$	—	$	—
Interest capitalized	$	3,372	$	4,470	$	9,470
Fair value of contingent consideration asset on date of divestiture	$	(1,137)	$	—	$	—
Foreign currency translation gain (loss) on equity method investments	$	9,193	$	(15,487)	$	12,519

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Gulfport Energy Corporation (“Gulfport” or the "Company"), a Delaware corporation formed in 1997, is an independent natural gas-weighted exploration and production company focused on the exploration, acquisition and production of natural gas, crude oil and natural gas liquids ("NGL") in the United States. The Company's principal properties are located in Eastern Ohio targeting the Utica formation and in central Oklahoma targeting the SCOOP Woodford and SCOOP Springer formations.

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 consolidated financial statements.

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, Gulfport MidCon, LLC, Mule Sky LLC and GRUS, LLC. All intercompany balances and transactions are eliminated in consolidation.

Accounts Receivable

The Company sells oil and natural gas to various purchasers and participates in drilling, completion and operation of oil and natural gas wells with joint interest owners on properties the Company operates. The related receivables are classified as accounts receivable—oil and natural gas sales and accounts receivable—joint interest and other, respectively. 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, 2019 and December 31, 2018.

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. Additionally, interest is capitalized on the cost of unproved oil and natural gas properties that are excluded from amortization for which exploration and development activities are in process or expected within the next 12 months.

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 proved 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, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company’s oil and natural gas revenue (only to the extent that the derivative instruments are treated as cash flow hedges for accounting purposes), and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of unproved properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can result in a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. As a result of the decline in commodity prices at December 31, 2019, the Company recognized a ceiling test impairment of $2.0 billion for the year ended December 31, 2019.

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 proved oil and gas reserves. Oil and gas properties not subject to amortization consist of the cost of unproved leaseholds and totaled approximately $1.7 billion and $2.9 billion at December 31, 2019 and December 31, 2018, 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 by recording 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 from3 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, 2016	$	(51,709)
December 31, 2017	$	(39,190)
December 31, 2018	$	(54,677)
December 31, 2019	$	(45,484)

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 2005 – 2018 U.S. federal and 1999 - 2018 state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2019, 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.

Revenue Recognition

The Company's revenues are primarily derived from the sale of natural gas, oil and condensate and NGL. Sales of natural gas, oil and condensate and NGL are recognized in the period that the performance obligations are satisfied. The Company generally considers the delivery of each unit (MMBtu or Bbl) to be separately identifiable and represents a distinct performance obligation that is satisfied at a point-in-time once control of the product has been transferred to the customer. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to (i) whether the purchaser can direct the use of the product, (ii) the transfer of significant risks, (iii) the Company's right to payment and (iv) transfer of legal title.

Revenue is measured based on consideration specified in the contract with the customer, and excludes any amounts collected on behalf of third parties. These contracts typically include variable consideration that is based on pricing tied to market indices and volumes delivered in the current month. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The payment date is usually within 30 days of the end of the calendar month in which the commodity is delivered.

The recognition of gains or losses on derivative instruments is outside the scope of Accounting Standards Codification ("ASC") 606, *Revenue from Contracts with Customers* ("ASC 606") and is not considered revenue from contracts with customers subject to ASC 606. The Company may use financial or physical contracts accounted for as derivatives as economic hedges to manage price risk associated with normal sales, or in limited cases may use them for contracts the Company intends to physically settle but do not meet all of the criteria to be treated as normal sales.

The Company has elected to exclude from the measurement of the transaction price all taxes assessed by governmental authorities that are both imposed on and concurrent with a specific revenue-producing transaction and collected by the Company from a customer, such as sales tax, use tax, value-added tax and similar taxes.

See Note 8 for additional discussion of revenue from contracts with customers.

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 consolidated statements 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. During the year ended December 31, 2019, the Company recorded an impairment of $160.8 million related to its investment in Mammoth Energy Services, Inc. ("Mammoth Energy") and an impairment of $32.4 million related to its investment in Grizzly Oil Sands ULC ("Grizzly"). There were no impairment charges recorded for the years ended December 31, 2017 and December 31, 2018. See Note 4 for further discussion of Mammoth Energy and Grizzly impairments.

Accounting for Stock-based Compensation

Share-based payments to employees, including grants of restricted stock, are 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. The Company does not recognize expense based on an estimate of forfeitures, but rather recognizes the impact of forfeitures only as they occur.

Derivative Instruments

The Company utilizes commodity derivatives to manage the price risk associated with forecasted sale of its natural gas, crude oil and NGL production. All derivative instruments are recognized as assets or liabilities in the consolidated balance sheets, measured at fair value. The Company does not apply hedge accounting to derivative instruments. 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 (loss) income or total operating cash flows.

Statements of Cash Flows

During the third quarter of 2019, the Company identified that certain activities were misclassified between cash flows from operating activities and cash flows from investing activities. These activities had been included in accounts payable, accrued liabilities and other and presented as cash flows from operating activities while they should have been presented as additions to oil and natural gas properties in cash flows from investing activities. The Company corrected the previously presented statements of cash flows for these additions and in doing so, for the year ended December 31, 2018, the consolidated statements of cash flows and the condensed consolidating statements of cash flows were adjusted to increase net cash flows provided by operating activities by $33.8 million with a corresponding increase in net cash flows used in investing activities. The Company has evaluated the effect of the incorrect presentation, both qualitatively and quantitatively, and concluded that it did not have a material impact on any previously filed annual or quarterly consolidated financial statements.

Recent Accounting Pronouncements

In January 2019, the Company adopted Accounting Standards Update ("ASU") No.2016-02, *Leases (Topic 842)* on a prospective basis using the simplified transition method permitted by ASU 2018-11, *Leases (Topic 842): Targeted Improvements.* See Note 9 for further discussion of the lease standard.

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. Subsequent to ASU 2016-13, the FASB issued several related ASU’s to clarify the application of the credit loss standard.

The guidance is effective for periods after December 15, 2019, with early adoption permitted. The Company adopted the standard as of January 1, 2020 with no material effect on its consolidated financial statements and related disclosures.

In July 2019, the FASB issued ASU No.2019-07, *Codification Updates to SEC Sections, Amendments to SEC Paragraphs Pursuant to SEC Final Rule Releases No. 33-10532, Disclosure Update and Simplification, and Nos. 33-10231 and 33-10442, Investment Company Reporting Modernization, and Miscellaneous Updates*. This ASU amends various SEC sections within the FASB Codification to align with the updated requirements of certain SEC final rules and includes miscellaneous updates to agree the language in the Codification to the electronic Code of Federal Regulations. ASU No. 2019-07 is effective upon issuance, and the Company has adopted the changes with no material impacts.

2. ACQUISITIONS AND DIVESTITURES

Sale of Southern Louisiana Assets

In December 2018, the Company entered into an agreement to sell its non-core assets located in the West Cote Blanche Bay ("WCBB") and Hackberry fields of Louisiana to an undisclosed third party for a purchase price of approximately $19.7 million. The sale closed on July 3, 2019, subject to customary post-closing terms and conditions, with an effective date of August 15, 2018. The Company received approximately $9.2 million in cash and retained contingent overriding royalty interests. In addition, the Company could also receive contingent payments based on commodity prices exceeding specified thresholds over the two years following the closing date. See Note 12 for further discussion of the contingent consideration arrangement, which was determined to be an embedded derivative. The buyer assumed all plugging and abandonment liabilities associated with these assets which totaled approximately $30.0 million at the divestiture date.

Sale of Non-operated Utica Interests

In December 2019, the Company entered into an agreement to divest certain non-operated interests in the Utica Shale for approximately $29.0 million in cash subject to customary closing terms and adjustments. This sale closed on December 30, 2019.

Sale of Bakken Overriding Royalty Interests

During 2019, the Company announced the sale of certain overriding royalty interests associated with assets the Company held in the Bakken. The sale closed on December 11, 2019 and, net of purchase price adjustments, the Company received approximately $7.0 million of total proceeds.

Vitruvian Acquisition

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 expenses of 2.4 million were incurred during the year ended December 31, 2017 related to the Vitruvian Acquisition.

For the period from the acquisition date of February 17, 2017 to December 31, 2017, the assets acquired in the Vitruvian Acquisition 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

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
		(In thousands, except share data)
Pro forma revenue	$	1,356,202
Pro forma net income	$	448,398
Pro forma earnings per share (basic)	$	2.49
Pro forma earnings per share (diluted)	$	2.49

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as ofDecember 31, 2019 and 2018 are as follows:

	December 31,			
	2019		2018	
	(In thousands)			
Oil and natural gas properties	$	10,595,735	$	10,026,836
Other depreciable property and equipment		91,198		87,146
Land		5,521		5,521
Total property and equipment		10,692,454		10,119,503
Accumulated depletion, depreciation, amortization and impairment		(7,228,660)		(4,640,098)
Property and equipment, net	$	3,463,794	$	5,479,405

Under the full cost method of accounting, capitalized costs of oil and natural gas properties are subject to a quarterly full cost ceiling test, which is discussed inNote 1. During the year ended December 31, 2019, the Company incurred $2.0 billion of impairments as a result of its oil and natural gas properties exceeding its calculated ceiling. The lower ceiling values resulted primarily from significant decreases in the 12-month average trailing prices for natural gas, oil and NGL, which significantly reduced proved reserves values and, to a lesser degree, proved reserves. No impairment of oil and natural gas properties was required under the ceiling test for the years endedDecember 31, 2018 and 2017.

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 $30.1 million, $37.7 million and $35.7 million for the years ended December 31, 2019, 2018 and 2017, 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 $1.08, $0.96 and $0.90 per Mcfe for the years ended December 31, 2019, 2018 and 2017, respectively.

The following is a summary of Gulfport's oil and natural gas properties not subject to amortization as ofDecember 31, 2019:

	Costs Incurred in				
	2019	2018	2017	Prior to 2017	Total
	(In thousands)				
Acquisition costs	$ 9,089	$ 98,870	$ 756,963	$ 806,982	$ 1,671,904
Exploration costs	259	—	—	—	259
Development costs	1,213	548	869	10,325	12,955
Capitalized interest	888	413	247	—	1,548
Total oil and natural gas properties not subject to amortization	$ 11,449	$ 99,831	$ 758,079	$ 817,307	$ 1,686,666

The following table summarizes the Company's non-producing properties excluded from amortization by area as ofDecember 31, 2019:

	December 31, 2019
	(In thousands)
Utica	$ 976,593
MidContinent	709,739
Other	334
	$ 1,686,666

As of December 31, 2018, approximately $2.9 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 endedDecember 31, 2019 and 2018 is as follows:

	December 31,	
	2019	2018
	(In thousands)	
Asset retirement obligation, beginning of period	$ 79,952	$ 75,100
Liabilities incurred	5,935	1,827
Liabilities settled	(273)	(719)
Liabilities removed due to divestitures	(30,146)	—
Accretion expense	3,939	4,119
Revisions in estimated cash flows	948	(375)
Asset retirement obligation as of end of period	$ 60,355	$ 79,952

4. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2019 and 2018:

	Approximate Ownership %	Carrying Value December 31, 2019	Carrying Value December 31, 2018	Loss (income) from equity method investments For the Year Ended December 31, 2019	2018	2017
		(In thousands)				
Investment in Tatex Thailand II, LLC	23.5%	$ —	$ —	$ (2,086)	$ (241)	$ (549)
Investment in Tatex Thailand III, LLC[(1)]	—%	—	—	—	—	(183)
Investment in Grizzly Oil Sands ULC	24.9999%	21,000	44,259	32,710	510	2,189
Investment in Timber Wolf Terminals LLC[(2)]	—%	—	—	—	536	8
Investment in Windsor Midstream LLC	22.5%	39	39	—	(9)	25,233
Investment in Stingray Cementing LLC[(3)]	—%	—	—	—	—	205
Investment in Blackhawk Midstream LLC[(4)]	—%	—	—	—	(38)	—
Investment in Stingray Energy Services LLC[(3)]	—%	—	—	—	—	282
Investment in Sturgeon Acquisitions LLC[(3)]	—%	—	—	—		(71)
Investment in Mammoth Energy Services, Inc.[(3)]	21.8%	11,005	191,823	179,524	(49,969)	(11,288)
Investment in Strike Force Midstream LLC[(5)]	—%	—	—	—	(693)	1,954
		$ 32,044	$ 236,121	$ 210,148	$ (49,904)	$ 17,780

(1) In December 2017, the Company received its final distribution from Tatex Thailand III, LLC ("Tatex III"), which was dissolved in 2017.
(2) On June 5, 2018, the Company received its final distribution from Timber Wolf Terminals LLC ("Timber Wolf"), which was dissolved in 2018.
(3) On June 5, 2017, Mammoth Energy acquired Stingray Cementing LLC, Stingray Energy Services LLC and Sturgeon Acquisitions LLC. See below under Mammoth Energy Services, Inc. for information regarding these transactions.
(4) On December 31, 2018, the Company received its final distribution from Blackhawk Midstream LLC ("Blackhawk"), which was dissolved in 2018.
(5) On May 1, 2018, the Company sold its 25% interest in Strike Force Midstream LLC ("Strike Force") to EQT Midstream Partners, LP for proceeds of $175.0 million in cash. As a result of the sale, the Company recognized a gain of $96.4 million net of transaction fees, which is included in gain on sale of equity method investments in the accompanying consolidated statement of operations.

The tables below summarize financial information for the Company's equity investments, as of December 31, 2019 and 2018.

Summarized balance sheet information:

	December 31, 2019	December 31, 2018
	(In thousands)	
Current assets	$ 421,326	$ 471,733
Noncurrent assets	$ 1,260,075	$ 1,302,488
Current liabilities	$ 132,569	$ 239,975
Noncurrent liabilities	$ 163,241	$ 94,575

Summarized results of operations:

	December 31,					
	2019		2018		2017	
			(In thousands)			
Gross revenue	$	625,012	$	1,729,778	$	755,374
Net (loss) income	$	(76,523)	$	253,451	$	(37,102)

Tatex Thailand II, LLC

The Company has an indirect ownership interest in Tatex Thailand II, LLC ("Tatex") and received$2.1 million in distributions from Tatex during the year ended December 31, 2019, of which $1.9 million related to proceeds from the sale of its interest in APICO ("APICO"), an international oil and gas exploration company. The Company received $0.2 million in distributions from Tatex during the year endedDecember 31, 2018. Tatex previously held an 8.5% interest in APICO before selling its interest in June 2019. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 108,000 acres which includes the Phu Horm Field.

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings Inc. ("Grizzly Holdings"), owns a24.9999% interest in Grizzly, a Canadian unlimited liability company. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc. As of December 31, 2019, Grizzly had approximately 830,000 acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada.

The Company reviewed its investment in Grizzly atDecember 31, 2019 for impairment based on certain qualitative and quantitative factors. The Company 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 indicated. This resulted in recording an impairment loss of $32.4 million for the year ended December 31, 2019, which is included in loss from equity method investments, net in the accompanying consolidated statements of operations. The Company reviewed its investment in Grizzly for impairment at December 31, 2018 and 2017 and determined no impairment was required.

The Company paid $0.4 million in cash calls during 2019 prior to its election to cease funding further capital calls. The Company paid $2.3 million in cash calls during the year ended December 31, 2018. Grizzly's functional currency is the Canadian dollar. The Company's investment in Grizzly was increased by a $9.0 million foreign currency translation gain, decreased by a $15.2 million foreign currency translation loss and increased by a $12.3 million foreign currency translation gain for the years ended December 31, 2019, 2018 and 2017, respectively. The Company had $44.8 million and $53.8 million in accumulated other comprehensive loss in its accompanying consolidated balance sheets related to Grizzly at December 31, 2019 and December 31, 2018, respectively, that will be included in the calculations of future charge related to a sale or abandonment.

Windsor Midstream LLC

At December 31, 2019, the Company held a 22.5% interest in Windsor Midstream LLC ("Midstream"), an entity controlled and managed by an unrelated third party. The Company received no distributions from Midstream during the years endedDecember 31, 2019 and 2018.

The Company has determined that Midstream is a variable interest entity ("VIE") but that the Company is not the primary beneficiary because it does not have a controlling financial interest in Midstream. This entity is considered a VIE because the limited partners lack substantive kick-out or participating rights over the general partner. The general partner has power to direct the activities that most significantly impact Midstream's economic performance. The Company accounts for its investment in 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 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.

Mammoth Energy Services, Inc.

On June 5, 2017, the Company contributed all of its membership interests inthree entities to Mammoth Energy in exchange for approximately 2.0 million shares of Mammoth Energy common stock. The Company accounted for this contribution as a sale of financial assets and recognized a gain of $12.5 million, which is included in gain on sale of equity method investments in the accompanying consolidated statements of operations for the year ended December 31, 2017.

On June 29, 2018, the Company sold 1,235,600 shares of its Mammoth Energy common stock in an underwritten public offering for net proceeds of approximately $47.0 million. In connection with the Company's public offering of a portion of its shares of Mammoth Energy common stock, the Company granted the underwriters an option to purchase additional shares of its Mammoth Energy common stock. On July 26, 2018, the underwriters exercised this option, in part, and on July 30, 2018, the Company sold an additional 118,974 shares for net proceeds of approximately $4.5 million. Following the sales of these shares, the Company owned 9,829,548 shares, or 21.9% at December 31, 2018, of Mammoth Energy's outstanding common stock. As a result of the sales, the Company recorded a gain of $28.3 million, which is included in gain on sale of equity method investments in the accompanying consolidated statements of operations. The approximate fair value of the Company's investment in Mammoth Energy's common stock at December 31, 2018 was $176.7 million based on the quoted market price of Mammoth Energy's common stock.

At December 31, 2019, the Company owned 9,829,548 shares, or 21.8%, of the outstanding common stock of Mammoth Energy. The Company reviewed its investment in Mammoth Energy during 2019 for impairment based on certain qualitative and quantitative factors. As a result of the calculated fair values and other qualitative factors, the Company concluded that an other than temporary impairment was indicated. This resulted in recording an impairment loss of $160.8 million for the year ended December 31, 2019, which is included in loss (income) from equity method investments, net in the accompanying consolidated statements of operations. If Mammoth Energy's common stock continues to trade below the Company's carrying value for a prolonged period of time, further impairment of the Company's investment in Mammoth Energy may be necessary. The Company's investment in Mammoth Energy was increased by a $0.2 million foreign currency gain, decreased by a $0.4 million foreign currency loss and increased by a $0.2 million foreign currency gain resulting from Mammoth Energy's foreign subsidiary for the years ended December 31, 2019, 2018 and 2017, respectively. During the year ended December 31, 2019, Gulfport received distributions of $2.5 million from Mammoth Energy as a result of $0.125 per share dividends in February 2019 and May 2019. During the year ended December 31, 2018, Gulfport received distributions of $2.5 million from Mammoth Energy as a result of dividends in August 2018 and November 2018. The approximate fair value of the Company's investment in Mammoth Energy's common stock at December 31, 2019 was $21.6 million based on the quoted market price of Mammoth Energy's common stock. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

5. LONG-TERM DEBT

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

	2019	2018
	(In thousands)	
Revolving credit agreement[1]	$ 120,000	$ 45,000
6.625% senior unsecured notes due 2023	329,467	350,000
6.000% senior unsecured notes due 2024	603,428	650,000
6.375% senior unsecured notes due 2025	529,525	600,000
6.375% senior unsecured notes due 2026	397,529	450,000
Net unamortized debt issuance costs[2]	(23,751)	(30,733)
Construction loan	22,453	23,149
Less: current maturities of long term debt	(631)	(651)
Debt reflected as long term	$ 1,978,020	$ 2,086,765

Maturities of long-term debt (excluding unamortized debt issuance costs) as ofDecember 31, 2019 are as follows:

	(In thousands)
2020	$ 631
2021	120,663
2022	694
2023	330,194
2024	604,186
Thereafter	946,034
Total	$ 2,002,402

(1) The Company has entered into a senior secured revolving credit facility, as amended (the "revolving credit facility"), with The Bank of Nova Scotia, as the lead arranger and administrative agent and other lenders. The revolving credit facility matures on December 13, 2021. On June 3, 2019, the Company further amended its revolving credit facility to, among other things, allow the Company to designate certain of its subsidiaries as unrestricted subsidiaries and to include LIBOR replacement provisions. The borrowing base was reaffirmed at $1.4 billion, and the Company's elected commitment amount remained at$1.0 billion. On November 25, 2019, the borrowing base under the Company's revolving credit facility was reduced to $1.2 billion, and the Company's elected commitment remained at$1.0 billion.

As of December 31, 2019, $120.0 million was outstanding under the revolving credit facility and the total availability for future borrowings under this facility, after giving effect to an aggregate of $243.6 million of letters of credit, was $636.4 million. The Company's wholly-owned subsidiaries have guaranteed the obligations of the Company under the revolving credit facility.

At December 31, 2019, amounts borrowed under the credit facility bore interest at a weighted average rate of3.30%.

The Company was in compliance with all covenants related to its outstanding indebtedness atDecember 31, 2019.

(2) Loan issuance costs related to the6.625% Senior Notes due 2023 (the "2023 Notes"), the6.000% Senior Notes due 2024 (the "2024 Notes"), the6.375% Senior Notes due 2025 (the "2025 Notes") and the 6.375% Senior Notes due 2026 (the "2026 Notes") (collectively the “Notes”) have been presented as a reduction to the principal amount of the Notes. At December 31, 2019, total unamortized debt issuance costs were$3.3 million for the 2023 Notes, $6.9 million for the 2024 Notes, $9.6 million for the 2025 Notes and $3.9 million for the 2026 Notes. In addition, loan commitment fee costs for the construction loan agreement described below were $0.1 million at December 31, 2019.

Debt Repurchases

In July of 2019, the Company's Board of Directors authorized $100 million of cash to be used to repurchase its senior notes in the open market at discounted values to par. In December 2019, the Company's Board of Directors increased the authorized size of its senior note repurchase program to $200 million in total. During the year ended December 31, 2019, the Company used borrowings under its revolving credit facility to repurchase in the open market approximately$190.1 million aggregate principal amount of its outstanding Notes for $138.8 million in cash. This included approximately $20.5 million principal amount of the 2023 Notes, $46.6 million principal amount of the 2024 Notes, $70.5 million principal amount of the 2025 Notes, and $52.5 million principal amount of the 2026 Notes. The Company recognized a $48.6 million gain on debt extinguishment, which included retirement of unamortized issuance costs and fees associated with the repurchased debt. This gain is included in gain on debt extinguishment in the accompanying consolidated statements of operations.

Interest Expense

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

	2019	2018	2017
		(In thousands)	
Cash paid for interest	$ 142,664	$ 132,995	$ 107,548
Change in accrued interest	(3,834)	7,266	12,524
Capitalized interest	(3,372)	(4,470)	(9,470)
Amortization of loan costs	6,328	6,121	5,011
Total interest expense	$ 141,786	$ 141,912	$ 115,613

The Company capitalized approximately $3.4 million and $4.5 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2019 and 2018, respectively.

Fair Value of Debt

At December 31, 2019, the carrying value of the outstanding debt represented by the Notes was approximately $1.8 billion. Based on the quoted market prices (Level 1), the fair value of the Notes was determined to be approximately $1.3 billion at December 31, 2019.

6. CHANGES IN CAPITALIZATION

Stock Repurchases

In January 2018, the board of directors of the Company approved a stock repurchase program to acquire up to $100 million of the Company's outstanding stock during 2018. In May 2018, the Company's board of directors authorized the expansion of its stock repurchase program, authorizing the Company to acquire up to an additional $100 million of its outstanding common stock during 2018 for a total of up to $200 million. The repurchase program did not require the Company to acquire any specific number of shares. This repurchase program was authorized to extend through December 31, 2018 and the Company repurchased 20.7 million shares of common stock in 2018 for $200.0 million in aggregate consideration.

In January 2019, the board of directors of the Company approved a new stock repurchase program to acquire a portion of the Company's outstanding common stock within a 24 month period. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and are 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. This repurchase program is authorized to extend through December 31, 2020. The program was suspended in the fourth quarter of 2019, but may be reactivated in the future depending on our projected leverage profile, commodity price outlook and market conditions.

For the year ended December 31, 2019, the Company repurchased 3.8 million shares for a cost of approximately $30.0 million under this repurchase program. Additionally, for the year ended December 31, 2019, the Company repurchased approximately 0.1 million shares for a cost of approximately $0.7 million to satisfy tax withholding requirements incurred upon the vesting of restricted stock. All repurchased shares have been canceled and returned to the status of authorized but unissued shares.

7. STOCK-BASED COMPENSATION

The Company adopted the 2005 Stock Incentive Plan ("2005 Plan") in January 2005. The 2005 Plan was amended and restated in April 2013 with the 2013 Restated Stock Incentive Plan ("2013 Plan"). During 2019, the Company further amended and restated the 2013 Plan with the 2019 Amended and Restated Stock Incentive Plan ("2019 Plan"). The 2019 Plan provides for grants of options, stock appreciation rights, restricted awards (restricted stock and restricted stock units) and performance awards to employees, consultants and directors of the Company that, in aggregate, do not exceed 12,500,000 shares. The 2019 Plan is administered by the Compensation Committee of the Company's board of directors (the "Committee"). Among other responsibilities, the Committee selects individuals to receive awards and establishes the terms of awards. As of December 31, 2019, the Company has awarded 8,673,254 restricted stock units and 2,009,144 performance vesting restricted stock units under the 2019 Plan.

During the years ended December 31, 2019, 2018 and 2017 the Company's stock-based compensation cost was $10.7 million, $11.3 million and $10.6 million, respectively, of which the Company capitalized $5.8 million, $4.5 million and $4.2

million, respectively, relating to its exploration and development efforts. Stock compensation costs, net of the amounts capitalized, are included in general and administrative expenses in the accompanying consolidated statements of operations.

The following table summarizes restricted stock unit and performance vesting restricted stock unit activity for the twelve months ended December 31, 2019, 2018 and 2017:

	Number of Unvested Restricted Stock Units		Weighted Average Grant Date Fair Value		Number of Unvested Performance Vesting Restricted Stock Units		Weighted Average Grant Date Fair Value
Unvested shares as of January 1, 2017	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	$	—	$	—
Granted	1,579,911	$	9.90	$	—	$	—
Vested	(626,671)		18.05		—		—
Forfeited	(393,456)		12.23		—		—
Unvested shares as of December 31, 2018	1,535,811	$	11.57	$	—	$	—
Granted	4,011,073		3.74		2,009,144		2.85
Vested	(676,108)		12.89		—		—
Forfeited	(772,458)		6.05		(225,484)		1.98
Unvested shares as of December 31, 2019	4,098,318	$	4.73		1,783,660	$	2.96

Restricted Stock Units

Restricted stock units awarded under the 2019 Plan generally vest over a period of one year in the case of directors and three years in the case of employees and vesting is dependent upon the recipient meeting applicable service requirements. Stock-based compensation costs are recorded ratably over the service period. The grant date fair value of restricted stock units represents the closing market price of the Company's common stock on the date of grant. Unrecognized compensation expense as of December 31, 2019 related to outstanding restricted stock units was $14.6 million. The expense is expected to be recognized over a weighted average period of 2.10 years.

Performance Vesting Restricted Stock Units

During the year ended December 31, 2019, the Company awarded performance vesting restricted stock units to certain of its executive officers under the 2019 Plan. The number of shares of common stock issued pursuant to the award will be based on relative total shareholder return ("RTSR"). RTSR is an incentive measure whereby participants will earn from 0% to 200% of the target award based on the Company's RTSR ranking compared to the RTSR of the companies in the Company's designated peer group at the end of the performance period. Awards will be earned and vested over a performance period measured from January 1, 2019 to December 31, 2021, subject to earlier termination of the performance period in the event of a change in control. The grant date fair value was determined using the Monte Carlo simulation method and is being recorded ratably over the performance period. Expected volatilities utilized in the Monte Carlo model were estimated using a historical period consistent with the remaining performance period of approximately two years. The risk-free interest rates were based on the U.S. Treasury rate for a term commensurate with the expected life of the grant. The Company assumed a range of risk-free interest rates of 1.56% to 2.42% and a range of expected volatilities of 29.1% to 85.1% to estimate the fair value of performance vesting units granted during the year ended December 31, 2019. Unrecognized compensation expense as of December 31, 2019 related to performance vesting restricted stock units was $4.2 million. The expense is expected to be recognized over a weighted average period of 2.38 years.

8. REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue Recognition

The Company's revenues are primarily derived from the sale of natural gas, oil and condensate and NGL. Sales of natural gas, oil and condensate and NGL are recognized in the period that the performance obligations are satisfied. The Company generally considers the delivery of each unit (MMBtu or Bbl) to be separately identifiable and represents a distinct performance obligation that is satisfied at the time control of the product is transferred to the customer. Revenue is measured based on consideration specified in the contract with the customer, and excludes any amounts collected on behalf of third parties. These contracts typically include variable consideration that is based on pricing tied to market indices and volumes delivered in the current month. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The payment date is usually within 30 days of the end of the calendar month in which the commodity is delivered.

Transaction Price Allocated to Remaining Performance Obligations

A significant number of the Company's product sales are short-term in nature generally through evergreen contracts with contract terms of one year or less. These contracts typically automatically renew under the same provisions. For those contracts, the Company has utilized the practical expedient allowed in the new revenue accounting standard that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For product sales that have a contract term greater than one year, the Company has utilized the practical expedient that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. Currently, the Company's product sales that have a contractual term greater than one year have no long-term fixed consideration.

Contract Balances

Receivables from contracts with customers are recorded when the right to consideration becomes unconditional, generally when control of the product has been transferred to the customer. Receivables from contracts with customers were $121.2 million and $210.2 million as of December 31, 2019 and December 31, 2018, respectively, and are reported in accounts receivable - oil and natural gas sales in the accompanying consolidated balance sheets. The Company currently has no assets or liabilities related to its revenue contracts, including no upfront or rights to deficiency payments.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain sales may be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The differences between the estimates and the actual amounts for product sales is recorded in the month that payment is received from the purchaser. For the year ended December 31, 2019, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

9. LEASES

Effective January 1, 2019, the Company adopted ASU No. 2016-02, *Leases (Topic 842).* The new standard supersedes the previous lease guidance by requiring lessees to recognize a right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year while maintaining substantially similar classifications for financing and operating leases. The Company adopted the new standard on a prospective basis using the simplified transition method permitted by ASU No. 2018-11, *Leases (Topic 842): Targeted Improvements.* Offsetting right-of-use assets and corresponding lease liabilities recognized by the Company on the adoption date totaled approximately $110 million, representing minimum payment obligations associated with identified leases with contractual durations exceeding one year. No cumulative-effect adjustment to retained earnings was required upon adoption of the new standard. The comparative information has not been restated and continues to be reported under the historic accounting standards in effect for those periods. The Company elected the package of practical expedients permitted under the new standard, which among other things, allows for lease and non-lease components in a contract to be accounted for as a single lease component for all asset classes and the carry forward of historical lease classifications.

Nature of Leases

The Company has operating leases associated with drilling rig commitments, pressure pumping services, field offices and other equipment with remaining lease terms with contractual durations in excess of one year. Short-term leases that have an initial term of one year or less are not capitalized.

The Company has entered into contracts for drilling rigs with third parties to ensure rig availability in its key operating areas. The Company has concluded its drilling rig contracts are operating leases as the assets are identifiable and the evaluation that the Company has the right to control the identified assets. The Company's drilling rig commitments are typically structured with an initial term of less than one year to two years and expire at various dates through 2020. These agreements typically include renewal options at the end of the initial term. Due to the nature of the Company's drilling schedules and potential volatility in commodity prices, the Company is unable to determine at commencement with reasonable certainty if the renewal options will be exercised; therefore, renewal options are not considered in the lease term for drilling contracts. The operating lease liabilities associated with these rig commitments are based on the minimum contractual obligations, primarily standby rates, and do not include variable amounts based on actual activity in a given period. Pursuant to the full cost method of accounting, these costs are capitalized as part of oil and natural gas properties on the accompanying consolidated balance sheets. A portion of these costs are borne by other interest owners.

Effective October 1, 2014, the Company entered into an Amended and Restated Master Services Agreement for pressure pumping services with Stingray Pressure Pumping LLC (“Stingray Pressure”), a subsidiary of Mammoth Energy and a related party. Pursuant to this agreement, as amended effective July 1, 2018, Stingray Pressure has agreed to provide hydraulic fracturing, stimulation and related completion and rework services to the Company through 2021 and the Company has agreed to pay Stingray Pressure a monthly service fee plus the associated costs of the services provided. The Company has the right to suspend services of one crew and only one crew at any point in time without payment, fee or other obligation associated with the suspended crew, given appropriate notification of suspension. The Company has determined that the agreement with Stingray Pressure is an operating lease due to the implicit identification of assets and the evaluation that the Company has the right to control the identified assets. The operating lease liability associated with this agreement is based on the minimum contractual obligations, which is the monthly service fee for one crew, and does not include variable amounts based on actual activity in a given period. Pursuant to the full cost method of accounting, these costs are capitalized as part of oil and natural gas properties on the accompanying consolidated balance sheets. A portion of these costs are borne by other interest owners. On December 18, 2019, the Company filed a lawsuit against Stingray Pressure to terminate this agreement. As the outcome of this lawsuit is unknown, the related right of use asset and operating lease liability are still recognized as of December 31, 2019 in the accompanying consolidated balance sheets.

The Company rents office space for its field locations and certain other equipment from third parties, which expire at various dates through 2024. These agreements are typically structured with non-cancelable terms of one to five years. The Company has determined these agreements represent operating leases with a lease term that equals the primary non-cancelable contract term. The Company has included any renewal options that it has determined are reasonably certain of exercise in the determination of the lease terms.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. The Company's incremental borrowing rate reflects the estimated rate of interest that it would pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment.

Maturities of operating lease liabilities as of December 31, 2019 were as follows:

		(In thousands)
2020	$	36,415
2021		22,569
2022		115
2023		90
2024		30
Total lease payments	$	59,219
Less: Imputed interest		(1,781)
Total	$	57,438

Lease cost for the year ended December 31, 2019 consisted of the following:

		(In thousands)
Operating lease cost	$	24,960
Operating lease cost - related party		22,440
Variable lease cost		2,172
Variable lease cost - related party		66,924
Short-term lease cost		834
Total lease cost(1)	$	117,330

(1) The majority of the Company's total lease cost was capitalized to the full cost pool, and the remainder was included in general and administrative expenses in the accompanying consolidated statements of operations.

Supplemental cash flow information for the year ended December 31, 2019 related to leases was as follows:

Cash paid for amounts included in the measurement of lease liabilities	(In thousands)
Operating cash flows from operating leases	182
Investing cash flow from operating leases	24,263
Investing cash flow from operating leases - related party	84,750

The weighted-average remaining lease term as of December 31, 2019 was 1.75 years. The weighted-average discount rate used to determine the operating lease liability as of December 31, 2019 was 3.52%.

10. INCOME TAXES

The income tax provision consists of the following:

		2019		2018		2017
				(In thousands)		
Current:						
State	$	—	$	(1,530)	$	2,167
Federal		(7)		253		3,362
Deferred:						
State		(7,556)		1,530		(118)
Federal		—		(322)		(3,602)
Total income tax (benefit) expense provision	$	(7,563)	$	(69)	$	1,809

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

	2019	2018	2017
		(In thousands)	
Income (loss) before federal income taxes	$ (2,009,921)	$ 430,491	$ 436,961
Expected income tax at statutory rate	(422,083)	90,403	152,936
State income taxes	(28,316)	(511)	2,299
Other differences	3,372	1,078	5,731
Remeasurement due to Tax Cut and Jobs Act	—	—	190,034
Change in valuation allowance due to current year activity	439,464	(91,039)	(158,704)
Change in valuation allowance due to Tax Cuts and Jobs Act	—	—	(190,487)
Income tax (benefit) expense recorded	$ (7,563)	$ (69)	$ 1,809

The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities atDecember 31, 2019, 2018 and 2017 are estimated as follows:

	2019	2018	2017
		(In thousands)	
Deferred tax assets:			
Net operating loss carryforward	$ 269,851	$ 164,363	$ 120,626
Oil and gas property basis difference	289,850	3,595	151,260
Investment in pass through entities	58,951	8,620	12,343
Stock-based compensation expense	1,440	616	813
Business energy investment tax credit	370	369	369
Charitable contributions carryover	297	269	255
Change in fair value of derivative instruments	11,219	2,761	—
Foreign tax credit carryforwards	943	2,009	2,074
Accrued liabilities	669	834	285
ARO liability	12,744	16,923	15,897
Non-oil and gas property basis difference	—	104	171
Lease liability	12,128	—	—
State net operating loss carryover	13,258	11,526	6,954
Interest expense carryforward	23,818	—	—
Total deferred tax assets	695,538	211,989	311,047
Valuation allowance for deferred tax assets	(647,575)	(211,987)	(298,830)
Deferred tax assets, net of valuation allowance	47,963	2	12,217
Deferred tax liabilities:			
Non-oil and gas property basis difference	1,859	—	—
Change in fair value of derivative instruments	26,410	2	11,009
Right of use asset	12,128	—	—
Other	3	—	—
Total deferred tax liabilities	40,400	2	11,009
Net deferred tax asset	$ 7,563	$ —	$ 1,208

The company recognized an income tax benefit of$7.6 million in 2019 and an income tax benefit of$69.0 thousand in 2018. The income tax benefit for 2019 consists mainly of a partial release of valuation allowance that was maintained against our Oklahoma deferred tax asset, as the Company believes that it can utilize a portion of its Oklahoma state NOL through carrybacks and carryforwards to offset Oklahoma sourced income from the sale of assets.

The Company has an available federal tax net operating loss carryforward estimated at approximately$1.3 billion as of December 31, 2019. This carryforward will begin to expire in the year 2023. The Company also has state net operating loss carryovers of $244.5 million that began to expire in 2019 and federal foreign tax credit carryovers of $0.9 million which began to expire in2019.

At each reporting period, the Company weighs all available positive and negative evidence to determine whether its deferred tax assets are more likely than not to be realized. As a result of this analysis at December 31, 2019, the Company determined a valuation allowance was necessary with respect to its deferred tax assets, except for its Oklahoma state NOL. The more significant evidential matter relates to the Company’s recent cumulative losses resulting primarily from impairments to the full cost pool during 2019 and the decline in commodity prices. At December 31, 2019, the Company has recorded a total valuation allowance of$647.6 million related to the federal and state net deferred tax assets for which it believes do not meet the more likely than not threshold.

There was an increase of$439.5 million, a decrease of $86.8 million and a decrease of $347.0 million to the valuation allowance during 2019, 2018 and 2017, respectively. The increase in the valuation allowance in 2019 was primarily due to increases in net deferred tax assets from pre-tax losses resulting from impairments in the Company's oil and natural gas properties. The decrease in the valuation allowance in 2018 was primarily due to decreases in net deferred tax assets due to pre-tax income. The decrease in the valuation allowance in 2017 was primarily due to pre-tax income and remeasurement of deferred tax assets due to the Tax Cuts and Jobs Act.

The Company’s ability to utilize NOL carryforwards and other tax attributes to reduce future federal taxable income is subject to potential limitations under Internal Revenue Code Section 382 ("Section 382") and its related tax regulations. The utilization of these attributes may be limited if certain ownership changes by 5% shareholders (as defined in Treasury regulations pursuant to Section 382) and the effects of stock issuances by the Company during any three-year period result in a cumulative change or more than 50% in the beneficial ownership of the Company. As of December 31, 2019, the Company has completed a Section 382 analysis, which reflects that no ownership change has occurred to further limit the use of NOL carryforwards or other tax attributes. There are conditions that exist that are beyond the Company’s control which could cause an ownership change in the future and create a significant limitation on the Company's ability to utilize those tax attributes.

As of December 31, 2019, the Company has recorded a liability associated with uncertain tax positions of$3.1 million.

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,								
	2019			2018			2017		
	Loss	Shares	Per Share	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)								
Basic:									
Net (loss) income	$(2,002,358)	160,341,125	$ (12.49)	$ 430,560	174,675,840	$ 2.46	$ 435,152	179,834,146	$ 2.42
Effect of dilutive securities:									
Stock options and awards	—	—		—	722,866		—	418,878	
Diluted:									
Net (loss) income	$(2,002,358)	160,341,125	$ (12.49)	$ 430,560	175,398,706	$ 2.45	$ 435,152	180,253,024	$ 2.41

There were 3,867,084 shares of common stock that were considered anti-dilutive for the year ended December 31, 2019. There were no potential shares of common stock that were considered anti-dilutive for the years ended December 31, 2018 and 2017.

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 NGL 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 natural gas, oil and NGL 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 and Mont Belvieu for propane, pentane and ethane. Below is a summary of the Company's open fixed price swap positions as of December 31, 2019.

	Index	Daily Volume (MMBtu/day)	Weighted Average Price
2020	NYMEX Henry Hub	548,000	$ 2.88

	Index	Daily Volume (Bbls/day)	Weighted Average Price
2020	NYMEX WTI	6,000	59.82

	Index	Daily Volume (Bbls/day)	Weighted Average Price
2020	Mont Belvieu C3	500	$ 21.63

In the third quarter of 2019, the Company sold call options in exchange for a premium, and used the associated premiums received to enhance the fixed price for a portion of the fixed price natural gas swaps primarily for 2020 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.

	Index	Daily Volume (MMBtu/day)	Weighted Average Price
2022	NYMEX Henry Hub	628,000	$ 2.90
2023	NYMEX Henry Hub	628,000	$ 2.90

For a portion of the natural gas fixed price swaps listed above, the counterparties had the option to extend the original terms an additional twelve months for the period January 2019 through December 2019. In December 2018, the counterparties chose to exercise all natural gas fixed price swaps, resulting in an additional 100,000 MMBtu per day at a weighted average price of $3.05 per MMBtu, which is included in the natural gas fixed price swaps listed above.

In addition, the Company entered into natural gas basis swap positions. As of December 31, 2019, the Company had the following natural gas basis swap positions open:

	Gulfport Pays	Gulfport Receives	Daily Volume (MMBtu/day)	Weighted Average Fixed Spread
2020	Transco Zone 4	NYMEX Plus Fixed Spread	60,000	$ (0.05)
2020	Fixed Spread	ONEOK Minus NYMEX	10,000	$ (0.54)

Contingent Consideration Arrangement

The purchase and sale agreement for the sale of the Company's non-core assets located in the WCBB and Hackberry fields of Louisiana included a contingent consideration arrangement that entitles the Company to receive bonus payments if commodity prices exceed specified thresholds. The calculated fair value of this contingent payment arrangement was approximately $1.1 million as of the closing date of the divestiture. See below for threshold and potential payment amounts.

Period	Threshold[(1)]		Payment to be received[(2)]
July 2020 - June 2021	Greater than or equal to $60.65	$	150,000
	Between $52.62 - $60.65		Calculated Value[(3)]
	Less than or equal to $52.62	$	—

(1) Based on the "WTI NYMEX + Argus LLS Differential," as published by Argus Media.
(2) Payment will be assessed monthly from July 2020 through June 2021. If threshold is met, payment shall be received within five business days after the end of each calendar month.
(3) If average daily price, as defined in (1), is greater than $52.62 but less than $60.65, payment received will be $150,000 multiplied by a fraction, the numerator of which is the amount determined by subtracting $52.62 from such average daily price, and the denominator of which is $8.03.

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, 2019 and 2018:

	December 31,		
	2019		2018
	(In thousands)		
Commodity derivative instruments	125,383		21,352
Contingent consideration arrangement	818		—
Total short-term derivative instruments – asset	126,201		21,352
Commodity derivative instruments	—		—
Contingent consideration arrangement	563		—
Total long-term derivative instruments – asset	563		—
Total short-term derivative instruments – liability	303	$	20,401
Total long-term derivative instruments – liability	53,135	$	13,992

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, 2019, 2018, and 2017.

	Net gain (loss) on derivative instruments		
	For the Year Ended December 31,		
	2019	2018	2017
	(In thousands)		
Natural gas derivatives	$ 194,450	$ (116,130)	$ 232,143
Oil derivatives	7,035	(13,084)	(3,350)
NGL derivatives	6,632	5,735	(15,114)
Contingent consideration arrangement	243	—	—
Total	$ 208,360	$ (123,479)	$ 213,679

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, 2019		
	Derivative instruments, gross	Netting adjustments	Derivative instruments, net
	(In thousands)		
Derivative assets	$ 126,764	$ (53,438)	$ 73,326
Derivative liabilities	$ (53,438)	$ 53,438	$ —

	As of December 31, 2018		
	Derivative instruments, gross	Netting adjustments	Derivative instruments, net
	(In thousands)		
Derivative assets	$ 21,352	$ (19,289)	$ 2,063
Derivative liabilities	$ (34,393)	$ 19,289	$ (15,104)

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. RESTRUCTURING COSTS

In the fourth quarter of 2019, the Company announced and completed a workforce reduction representing approximately13% of its headcount. In connection with the reduction, the Company incurred a total charge of approximately $4.6 million, primarily consisting of one-time employee-related termination benefits, with a remaining liability of $0.2 million at December 31, 2019.

14. FAIR VALUE MEASUREMENTS

The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value. Fair value is 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. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. Fair value measurements are 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 valuation level as ofDecember 31, 2019 and 2018:

	December 31, 2019		
	Level 1	Level 2	Level 3

		(In thousands)	
Assets:			
Derivative Instruments	$ —	126,764	$ —
Liabilities:			
Derivative Instruments	$ —	53,438	$ —

	December 31, 2018		
	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Derivative Instruments	$ —	$ 21,352	$ —
Liabilities:			
Derivative Instruments	$ —	$ 34,393	$ —

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 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 and upward revisions recognized during the year ended December 31, 2019 were approximately $5.9 million and $0.9 million, respectively.

Due to the unobservable nature of the inputs, the fair value of the Company's investment in Grizzly as ofDecember 31, 2019 was estimated using assumptions that represent Level 3 inputs.

The fair value of the Company's investment in Mammoth Energy as ofDecember 31, 2019 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.

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 Company's construction loan is carried at cost, which approximates market value based on the borrowing rates currently available to the Company with similar terms and maturities. See Note 5 for fair value of Company's long-term debt.

15. RELATED PARTY TRANSACTIONS

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

As of December 31, 2019, the Company held approximately 21.8% of Mammoth Energy's outstanding common stock as discussed above inNote 4. Approximately $0.6 million, $2.0 million, and $2.1 million of services provided by Mammoth Energy are included in lease operating expenses in the consolidated statements of operations for the years ended December 31, 2019, 2018 and 2017, respectively. Approximately $109.9 million and $139.7 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, 2019 and 2018, respectively. At December 31, 2019 and 2018, the Company owed Mammoth Energy approximately $8.4 million and $10.9 million, respectively, related to these services.

The Company previously held a 25% interest in Strike Force, who develops natural gas gathering assets in dedicated areas. In May 2018, the Company sold its interest in Strike Force as discussed above in Note 4. Approximately $18.5 million and $23.1 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, 2018 and December 31, 2017, respectively.

16. COMMITMENTS

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) and Profit Sharing plan under which eligible employees may contribute up to100% of their total compensation up to the maximum pre-tax threshold through salary deferrals. Also under the plan, the Company made bi-weekly contributions 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, 2019, 2018 and 2017, Gulfport incurred $2.9 million, $2.6 million, and $3.0 million, respectively, in contributions expense related to this plan.

Future Sales Commitments

The Company has entered into various firm sales contracts to deliver and sell natural gas. The Company expects to fulfill its delivery commitments primarily with production from proved developed reserves. The Company's proved reserves have generally been sufficient to satisfy its delivery commitments during the three most recent years, and it expects such reserves will continue to be the primary means of fulfilling its future commitments. However, where the Company's proved reserves are not sufficient to satisfy its delivery commitments, it can and may use spot market purchases to satisfy the commitments.

A summary of these commitments at December 31, 2019 are set forth in the table below:

	(MMBtu per day)
2020	326,000
2021	192,000
2022	70,000
2023	17,000
2024	—
Thereafter	—
Total	605,000

Future Firm Transportation Commitments

The Company has contractual commitments with pipeline carriers for future transportation of natural gas from the Company's production areas to downstream markets. Commitments related to future firm transportation agreements are not recorded as obligations in the accompanying consolidated balance sheets; however, they are reflected in the Company's estimates of proved reserves.

A summary of these commitments at December 31, 2019 are set forth in the table below:

	Total MMBtu		(In thousands)
2020	505,080,000	$	274,813
2021	531,075,000		286,626
2022	531,075,000		286,626
2023	515,867,000		282,945
2024	489,525,000		265,568
Thereafter	3,778,217,000		2,163,926
Total	6,350,839,000	$	3,560,504

Other Commitments

Effective October 1, 2014, the Company entered into a Sand Supply Agreement with Muskie Proppant LLC (“Muskie”), a subsidiary of Mammoth Energy and a related party. Pursuant to this agreement, as amended effective August 3, 2018, the Company has agreed to purchase annual and monthly amounts of proppant sand subject to exceptions specified in the agreement at agreed pricing plus agreed costs and expenses through 2021. 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 $3.5 million and $2.2 million related to non-utilization fees during the years ended December 31, 2019 and 2018.

Future minimum commitments under these agreements at December 31, 2019 are as follows:

		(In thousands)
2020	$	7,500
2021		7,500
Total	$	15,000

17. CONTINGENCIES

Litigation and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings that may result in material liabilities, including those described below. Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is indeterminate. The Company's total accrued liabilities in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, its experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. Significant judgment is required in making these estimates and their final liabilities may ultimately be materially different.

The Company, along with a number of other oil and gas companies, has been named as a defendant 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 (together, the "Complaints"). The Complaints allege that certain of the defendants’ operations violated the State and Local Coastal Resources Management Act of 1978, as amended, and the rules, regulations, orders and ordinances adopted thereunder (the "CZM Laws") by causing substantial damage to land and waterbodies located in the coastal zone of the relevant Parish. 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 interest. The United States District Court for the Western District of Louisiana issued orders remanding the cases to their respective state court, and the defendants have appealed the remand orders to the 5th Circuit Court of Appeals.

In July 2019, Pigeon Land Company, Inc., a successor in interest to certain of the Company's legacy Louisiana properties, filed an action against the Company and a number of other oil and gas companies in the 16th Judicial District Court for the Parish of Iberia in Louisiana. The suit alleges negligence, strict liability and various violations of Louisiana statutes relating to property damage in connection with the historic development of the Company's Louisiana properties and seeks unspecified damages (including punitive damages), an injunction to return the affected property to its original condition, and the payment of reasonable attorney fees and legal expenses and interest.

In September 2019, a stockholder of Mammoth Energy filed a derivative action on behalf of Mammoth Energy against members of Mammoth Energy's board of directors, including a director designated by the Company, and its significant stockholders, including the Company, in the United States District Court for the Western District of Oklahoma. In January 2020, plaintiffs consolidated actions against the same defendants in the United States District Court for the District of Delaware. The consolidated and amended complaint alleges, among other things, that the Company breached its fiduciary duties and misappropriated information as a controlling shareholder of Mammoth Energy in connection with Mammoth Energy's activities in Puerto Rico following Hurricane Maria and the Company's secondary offering of Mammoth Energy common stock in June 2018. The complaint seeks unspecified damages, the payment of reasonable attorney fees and legal expenses and interest and to force Mammoth Energy and its board of directors to make specified corporate governance reforms.

In October 2019, Saydee Resources, LLC, on behalf of itself and a class of similarly situated royalty holders, filed an action against the Company in the District Court of Grady County Oklahoma. The suit alleges that the Company underpaid royalty holders and seeks unspecified damages for breach of contract, tortious breach of contract, fraud and unjust enrichment.

In October 2019, Kelsie Wagner, in her capacity as trustee of various trusts and on behalf of the trusts and other similarly situated royalty owners, filed an action against us in the District Court of Grady County, Oklahoma. The suit alleges that the Company underpaid royalty owners and seeks unspecified damages for violations of the Oklahoma Production Revenue Standards Act and fraud.

SEC Investigation

The SEC has commenced an investigation with respect to certain actions by former Company management, including alleged improper personal use of Company assets, and potential violations by former management and the Company of the Sarbanes-Oxley Act of 2002 in connection with such actions. We have fully cooperated and intend to continue to cooperate fully with the SEC's investigation. Although it is not possible to predict the ultimate resolution or financial liability with respect to this matter, the Company believes that the outcome of this matter will not have a material effect on the Company's business, financial condition or results of operations.

Business Operations

The Company is involved in various lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions.

Environmental Contingencies

The nature of the oil and gas business carries with it certain environmental risks for Gulfport and its subsidiaries. They have implemented various policies, programs, procedures, training and audits to reduce and mitigate such environmental risks. They conduct periodic reviews, on a company-wide basis, to assess changes in their environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. The Company manages its exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and address the potential liability. Depending on the extent of an identified environmental concern, they may, among other things, exclude a property from the transaction, require the seller to remediate the property to their satisfaction in an acquisition or agree to assume liability for the remediation of the property.

The Company received several Finding of Violation (“FOVs”) from the United States Environmental Protection Agency ("USEPA") alleging violations of the Clean Air Act in Ohio. The first FOV for one site was dated December 11, 2013. Two subsequent FOVs incorporated and expanded the scope on January 4, 2017 and April 15, 2019. The Company entered into a settlement with the Department of Justice and USEPA agreeing to pay $1.7 million and invest in improvements at 17 well pads. The settlement was filed with the U.S. District Court for the Southern District of Ohio in January 2020, and is pending approval.

Other Matters

Based on management’s current assessment, they are of the opinion that no pending or threatened lawsuit or dispute relating to its business operations is likely to have a material adverse effect on their future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management’s estimates.

Insurance Proceeds

For the years ended December 31, 2019 and 2018 the Company was reimbursed $0.1 million and $0.2 million, respectively, net of related legal fees by its insurance provider, which is included in other expense (income) in the accompanying consolidated statements of operations. There were no insurance proceeds received in the year ended December 31, 2017.

Concentration of Credit Risk

Gulfport operates in the oil and natural gas industry principally in the states of Ohio and Oklahoma 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, 2019, Gulfport held cash in excess of insured limits in these banks totaling $5.6 million.

During the year ended December 31, 2019, one customer accounted for approximately 14% of the Company's total sales. During the year ended December 31, 2018, two customers accounted for approximately 17% and 10% of the Company's total sales. During the year ended December 31, 2017, one customer accounted for approximately 40% of the Company's total sales. The Company does not believe that the loss of any of these customers would have a material adverse effect on its natural gas, oil and condensate and NGL sales as alternative customers are readily available.

18. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

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 revolving credit facility or certain other debt (the "Guarantors"). The Notes are not guaranteed by Grizzly Holdings, Mule Sky LLC ("Mule Sky") or GRUS, LLC ("GRUS") (the “Non-Guarantors”). 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. Effective June 1, 2019, the Parent contributed interests in certain oil and gas assets and related liabilities to certain of the Guarantors.

The following condensed consolidating balance sheets, statements of operations, statements of comprehensive income and statements of cash flows are provided for the Parent, the Guarantors and the Non-Guarantors 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-Guarantors.

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2019				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 2,768	$ 3,097	$ 195	$ —	$ 6,060
Accounts receivable - oil and natural gas sales	859	120,351	—	—	121,210
Accounts receivable - joint interest and other	5,279	42,696	—	—	47,975
Accounts receivable - intercompany	1,065,593	843,223	—	(1,908,816)	—
Prepaid expenses and other current assets	4,047	308	76	—	4,431
Short-term derivative instruments	126,201	—	—	—	126,201
Total current assets	1,204,747	1,009,675	271	(1,908,816)	305,877
Property and equipment:					
Oil and natural gas properties, full-cost accounting	1,314,933	9,273,681	7,850	(729)	10,595,735
Other property and equipment	92,650	50	4,019	—	96,719
Accumulated depletion, depreciation, amortization and impairment	(1,418,888)	(5,808,254)	(1,518)	—	(7,228,660)
Property and equipment, net	(11,305)	3,465,477	10,351	(729)	3,463,794
Other assets:					
Equity investments and investments in subsidiaries	3,064,503	6,332	21,000	(3,059,791)	32,044
Long-term derivative instruments	563	—	—	—	563
Deferred tax asset	7,563	—	—	—	7,563
Inventories	—	5,182	—	—	5,182
Operating lease assets	14,168	—	—	—	14,168
Operating lease assets - related parties	43,270	—	—	—	43,270
Other assets	10,026	332			10,358
Total other assets	3,140,093	11,846	21,000	(3,059,791)	113,148
Total assets	$ 4,333,535	$ 4,486,998	$ 31,622	$ (4,969,336)	$ 3,882,819
Liabilities and stockholders' equity					
Current liabilities:					
Accounts payable and accrued liabilities	$ 48,006	$ 367,088	$ 124	$ —	$ 415,218
Accounts payable - intercompany	878,283	1,026,249	4,285	(1,908,817)	—
Short-term derivative instruments	303	—	—	—	303
Current portion of operating lease liabilities	13,826	—	—	—	13,826
Current portion of operating lease liabilities - related parties	21,220	—	—	—	21,220
Current maturities of long-term debt	631	—	—	—	631
Total current liabilities	962,269	1,393,337	4,409	(1,908,817)	451,198
Long-term derivative instruments	53,135	—	—	—	53,135
Asset retirement obligation - long-term	—	58,322	2,033	—	60,355
Uncertain tax position liability	3,127	—	—	—	3,127
Non-current operating lease liabilities	342	—	—	—	342
Non-current operating lease liabilities - related parties	22,050	—	—	—	22,050
Long-term debt, net of current maturities	1,978,020	—	—	—	1,978,020
Total liabilities	3,018,943	1,451,659	6,442	(1,908,817)	2,568,227
Stockholders' equity:					
Common stock	1,597	—	—	—	1,597
Paid-in capital	4,207,554	4,171,408	267,557	(4,438,965)	4,207,554
Accumulated other comprehensive loss	(46,833)	—	(44,763)	44,763	(46,833)
Accumulated deficit	(2,847,726)	(1,136,069)	(197,614)	1,333,683	(2,847,726)
Total stockholders' equity	1,314,592	3,035,339	25,180	(3,060,519)	1,314,592
Total liabilities and stockholders' equity	$ 4,333,535	$ 4,486,998	$ 31,622	$ (4,969,336)	$ 3,882,819

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2018				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets					
Cash and cash equivalents	$ 25,585	$ 26,711	$ 1	$ —	$ 52,297
Accounts receivable - oil and natural gas	146,075	64,125	—	—	210,200
Accounts receivable - joint interest and other	16,212	6,285	—	—	22,497
Accounts receivable - intercompany	671,633	319,464	—	(991,097)	—
Prepaid expenses and other current assets	7,843	2,174	—	—	10,017
Short-term derivative instruments	21,352	—	—	—	21,352
Total current assets	888,700	418,759	1	(991,097)	316,363
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	7,044,550	2,983,015	—	(729)	10,026,836
Other property and equipment	91,916	751	—	—	92,667
Accumulated depletion, depreciation, amortization and impairment	(4,640,059)	(39)	—	—	(4,640,098)
Property and equipment, net	2,496,407	2,983,727	—	(729)	5,479,405
Other assets:					
Equity investments and investments in subsidiaries	2,856,988	—	44,259	(2,665,126)	236,121
Inventories	4,210	1,134	—	—	5,344
Other assets	12,624	1,178	—	1	13,803
Total other assets	2,873,822	2,312	44,259	(2,665,125)	255,268
Total assets	$ 6,258,929	$ 3,404,798	$ 44,260	$ (3,656,951)	$ 6,051,036
Liabilities and stockholders' equity					
Current liabilities:					
Accounts payable and accrued liabilities	$ 419,107	$ 99,273	$ —	$ —	$ 518,380
Accounts payable - intercompany	320,259	670,708	130	(991,097)	—
Short-term derivative instruments	20,401	—	—	—	20,401
Current maturities of long-term debt	651	—	—	—	651
Total current liabilities	760,418	769,981	130	(991,097)	539,432
Long-term derivative instruments	13,992	—	—	—	13,992
Asset retirement obligation - long-term	66,859	13,093	—	—	79,952
Uncertain tax position liability	3,127	—	—	—	3,127
Long-term debt, net of current maturities	2,086,765	—	—	—	2,086,765
Total liabilities	2,931,161	783,074	130	(991,097)	2,723,268
Stockholders' equity:					
Common stock	1,630	—	—	—	1,630
Paid-in capital	4,227,532	1,915,598	261,626	(2,177,224)	4,227,532
Accumulated other comprehensive loss	(56,026)	—	(53,783)	53,783	(56,026)
(Accumulated deficit) retained earnings	(845,368)	706,126	(163,713)	(542,413)	(845,368)
Total stockholders' equity	3,327,768	2,621,724	44,130	(2,665,854)	3,327,768
Total liabilities and stockholders' equity	$ 6,258,929	$ 3,404,798	$ 44,260	$ (3,656,951)	$ 6,051,036

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2019				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 524,089	$ 821,919	$ —	$ —	$ 1,346,008
Costs and expenses:					
Lease operating expenses	26,923	56,075	—	—	82,998
Production taxes	6,117	22,454	—	—	28,571
Midstream gathering and processing expenses	71,420	220,305	—	—	291,725
Depreciation, depletion and amortization	203,921	345,504	683	—	550,108
Impairment of oil and gas properties	—	2,039,770	—	—	2,039,770
General and administrative expenses	71,219	(23,748)	508	—	47,979
Restructuring costs	4,611	—	—	—	4,611
Accretion expense	1,390	2,549	—	—	3,939
	385,601	2,662,909	1,191	—	3,049,701
INCOME (LOSS) FROM OPERATIONS	138,488	(1,840,990)	(1,191)	—	(1,703,693)
OTHER (INCOME) EXPENSE:					
Interest expense	144,645	(2,859)	—	—	141,786
Interest income	(501)	(300)	—	—	(801)
Gain on debt extinguishment	(48,630)	—	—	—	(48,630)
Loss (income) from equity method investments and investments in subsidiaries	2,053,533		32,710	(1,876,095)	210,148
Other (income) expense, net	(638)	3,364	—	999	3,725
	2,148,409	205	32,710	(1,875,096)	306,228
(LOSS) INCOME BEFORE INCOME TAXES	(2,009,921)	(1,841,195)	(33,901)	1,875,096	(2,009,921)
INCOME TAX BENEFIT	(7,563)	—	—	—	(7,563)
NET (LOSS) INCOME	$ (2,002,358)	$ (1,841,195)	$ (33,901)	$ 1,875,096	$ (2,002,358)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2018				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 839,241	$ 515,803	$ —	$ —	$ 1,355,044
Costs and expenses:					
Lease operating expenses	66,947	24,693	—	—	91,640
Production taxes	17,140	16,340	—	—	33,480
Midstream gathering and processing expenses	199,607	90,581	—	—	290,188
Depreciation, depletion and amortization	486,661	3	—	—	486,664
General and administrative expenses	52,664	(2,673)	3	—	49,994
Accretion expense	3,228	891	—	—	4,119
	826,247	129,835	3	—	956,085
INCOME (LOSS) FROM OPERATIONS	12,994	385,968	(3)	—	398,959
OTHER (INCOME) EXPENSE:					
Interest expense	144,533	(2,621)	—	—	141,912
Interest income	(287)	(27)	—	—	(314)
Gain on sale of equity method investments	(28,349)	(96,419)	—	—	(124,768)
(Income) loss from equity method investments and investments in subsidiaries	(532,869)	(694)	510	483,149	(49,904)
Other (income) expense, net	(525)	(33)	—	2,100	1,542
	(417,497)	(99,794)	510	485,249	(31,532)
INCOME (LOSS) BEFORE INCOME TAXES	430,491	485,762	(513)	(485,249)	430,491
INCOME TAX BENEFIT	(69)	—	—	—	(69)
NET INCOME (LOSS)	$ 430,560	$ 485,762	$ (513)	$ (485,249)	$ 430,560

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 expenses	187,678	61,317	—	—	248,995
Depreciation, depletion and amortization	364,625	4	—	—	364,629
Impairment of oil and natural gas properties	—	—	—	—	—
General and administrative expenses	48,174	(2,654)	3	—	45,523
Accretion expense	1,246	365	—	—	1,611
Acquisition expense	—	2,392	—	—	2,392
	682,616	81,903	3	—	764,522
INCOME (LOSS) FROM OPERATIONS	328,373	227,411	(3)	—	555,781
OTHER (INCOME) EXPENSE:					
Interest expense	120,147	(4,534)	—	—	115,613
Interest income	(988)	(21)	—	—	(1,009)
Gain on sale of equity method investments	(12,523)	—	—	—	(12,523)
(Income) loss from equity method investments and investments in subsidiaries	(213,607)	1,955	2,189	227,243	17,780
Other (income) expense, net	(1,617)	(324)	—	900	(1,041)
	(108,588)	(2,924)	2,189	228,143	118,820
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 COMPREHENSIVE INCOME (LOSS)
(Amounts in thousands)

	Year Ended December 31, 2019				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$ (2,002,358)	$ (1,841,195)	$ (33,901)	$ 1,875,096	$ (2,002,358)
Foreign currency translation adjustment	9,193	173	9,020	(9,193)	9,193
Other comprehensive loss (income)	9,193	173	9,020	(9,193)	9,193
Comprehensive income (loss)	$ (1,993,165)	$ (1,841,022)	$ (24,881)	$ 1,865,903	$ (1,993,165)

	Year Ended December 31, 2018				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$ 430,560	$ 485,762	$ (513)	$ (485,249)	$ 430,560
Foreign currency translation adjustment	(15,487)	(297)	(15,190)	15,487	(15,487)
Other comprehensive (loss) income	(15,487)	(297)	(15,190)	15,487	(15,487)
Comprehensive income (loss)	$ 415,073	$ 485,465	$ (15,703)	$ (469,762)	$ 415,073

	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

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Year Ended December 31, 2019				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$ 64,037	$ 656,443	$ 3,510	$ 3	$ 723,993
Net cash provided by (used in) investing activities	8,605	(680,057)	(3,751)	432	(674,771)
Net cash (used in) provided by financing activities	(95,459)	—	435	(435)	(95,459)
Net (decrease) increase in cash and cash equivalents	(22,817)	(23,614)	194	—	(46,237)
Cash and cash equivalents at beginning of period	25,585	26,711	1	—	52,297
Cash and cash equivalents at end of period	$ 2,768	$ 3,097	$ 195	$ —	$ 6,060

	Year Ended December 31, 2018				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$ 560,203	$ 226,067	$ —	$ 1	$ 786,271
Net cash (used in) provided by investing activities	(445,869)	(231,005)	(2,318)	2,318	(676,874)
Net cash (used in) provided by financing activities	(156,657)	—	2,319	(2,319)	(156,657)
Net (decrease) increase in cash and cash equivalents	(42,323)	(4,938)	1	—	(47,260)
Cash and cash equivalents at beginning of period	67,908	31,649	—	—	99,557
Cash and cash equivalents at end of period	$ 25,585	$ 26,711	$ 1	$ —	$ 52,297

	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	(2,216,615)	(1,674,690)	(2,280)	1,419,417	(2,474,168)
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	(1,390,974)	29,656	—	—	(1,361,318)
Cash and cash equivalents at beginning of period	1,458,882	1,993	—	—	1,460,875
Cash and cash equivalents at end of period	$ 67,908	$ 31,649	$ —	$ —	$ 99,557

19. 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

	2019	2018
	(In thousands)	
Proved properties	$ 8,909,069	$ 7,153,799
Unproved properties	1,686,666	2,873,037
	10,595,735	10,026,836
Accumulated depreciation, depletion, amortization and impairment	(7,191,957)	(4,613,293)
Net capitalized costs	$ 3,403,778	$ 5,413,543
Equity investment in Grizzly Oil Sands ULC		
Proved properties	$ 64,476	$ 67,475
Unproved properties	85,395	79,605
	149,871	147,080
Accumulated depreciation, depletion, amortization and impairment	(1,634)	(1,553)
Net capitalized costs	$ 148,237	$ 145,527

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	2019	2018	2017
		(In thousands)	
Acquisition	$ 37,598	$ 119,444	$ 1,946,416
Development	594,673	714,269	1,138,951
Exploratory	9,762	22,081	9,058
Total	$ 642,033	$ 855,794	$ 3,094,425
Equity investment in Grizzly Oil Sands ULC			
Acquisition	$ —	$ 238	$ 503
Development	—	—	—
Exploratory	849	—	—
Total	$ 849	$ 238	$ 503

Capitalized interest is included as part of the cost of oil and natural gas properties. The Company capitalized $3.4 million, $4.5 million and $9.5 million during 2019, 2018, and 2017, respectively, based on the Company's weighted average cost of borrowings used to finance expenditures.

In addition to capitalized interest, the Company capitalized internal costs totaling $30.1 million, $37.7 million and $35.7 million during 2019, 2018, and 2017, respectively, which were directly related to the acquisition, exploration and development of the Company's oil and natural gas properties.

Results of Operations for Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and natural 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.

	2019	2018	2017
		(In thousands)	
Revenues	$ 1,137,648	$ 1,478,523	$ 1,106,624
Production costs	(403,294)	(415,308)	(350,367)
Depletion	(539,379)	(476,517)	(358,792)
Impairment	(2,039,770)	—	—
Income tax benefit	7,563	68	240
Results of operations from producing activities	$ (1,837,232)	$ 586,766	$ 397,705
Depletion per Mcf of gas equivalent (Mcfe)	$ 1.08	$ 0.96	$ 0.90

Results of Operations from equity method investment in Grizzly Oil Sands ULC			
Revenues	$ —	$ —	$ —
Production costs	—	—	—
Depletion	—	—	—
Income tax expense	—	—	—
Results of operations from producing activities	$ —	$ —	$ —

Oil and Natural Gas Reserves

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as ofDecember 31, 2019, 2018 and 2017 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, 2019, 2018 and 2017, 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 2019 reserve report are $55.85 per barrel of oil, $2.58 per MMbtu and $21.25 per barrel for NGL, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively. The prices used at December 31, 2018 and 2017 for reserve report purposes are $65.56 per barrel, $3.10 per MMbtu and $32.02 per barrel for NGL and $51.34 per barrel, $2.98 per MMbtu and $18.40 per barrel for NGL, 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.

	2019			2018			2017		
	Oil	Natural Gas	NGL	Oil	Natural Gas	NGL	Oil	Natural Gas	NGL
	(Mbbls)	(MMcf)	(Mbbls)	(Mbbls)	(MMcf)	(Mbbls)	(Mbbls)	(MMcf)	(Mbbls)
Proved Reserves									
Beginning of the period	21,050	4,133,889	80,520	19,157	4,825,310	75,766	5,546	2,167,068	20,127
Purchases in oil and natural gas reserves in place	—	—	—	—	—	—	15,132	1,098,644	53,617
Extensions and discoveries	3,612	997,014	12,992	5,205	622,271	9,631	951	1,594,734	4,619
Sales of oil and natural gas reserves in place	(2,369)	(62,557)	—	(134)	(43,444)	(112)	—	—	—
Revisions of prior reserve estimates	(1,749)	(561,890)	(26,909)	(377)	(826,506)	1,228	107	314,925	2,737
Current production	(2,186)	(458,178)	(5,074)	(2,801)	(443,742)	(5,993)	(2,579)	(350,061)	(5,334)
End of period	18,357	4,048,279	61,528	21,050	4,133,889	80,520	19,157	4,825,310	75,766
Proved developed reserves	7,887	1,757,303	29,898	9,570	1,813,184	40,810	10,245	1,616,930	36,247
Proved undeveloped reserves	10,470	2,290,976	31,630	11,480	2,320,705	39,710	8,912	3,208,380	39,519
Equity investment in Grizzly Oil Sands ULC									
Beginning of the period	—	—	—	—	—	—	—	—	—
Purchases in oil and natural gas reserves in place	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	—	—	—	—	—	—	—	—
Revisions of prior reserve estimates	—	—	—	—	—	—	—	—	—
Current production	—	—	—	—	—	—	—	—	—
End of period	—	—	—	—	—	—	—	—	—
Proved developed reserves	—	—	—	—	—	—	—	—	—
Proved undeveloped reserves	—	—	—	—	—	—	—	—	—

In 2019, the Company experienced extensions of 1.1 Tcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica Shale and SCOOP acreages. Of the total extensions, 793.5 Bcfe was attributable to the addition of 72 PUD locations in the Utica field, 302.9 Bcfe was attributable to the addition of 37 PUD locations in the SCOOP field. The Company experienced total downward revisions of approximately 733.8 Bcfe in estimated proved reserves, of which 347.2 Bcfe was a result of the exclusion of nine PUD locations in the Utica field and 22 PUD locations in the SCOOP field, which was a result of changes in the Company's schedule that moved development of these PUD locations beyond five years of initial booking. The development plan change reflects the Company's commitment capital discipline and funding future activities within cash flow. An additional 296.4 Bcfe in downward revisions was the result of commodity price changes. Commodity prices experienced volatility throughout 2019 and the 12-month average price for natural gas decreased from $3.10 per MMBtu for 2018 to $2.58 per MMBtu for 2019, the 12-month average price for NGL decreased from $32.02 per barrel for 2018 to $21.25 per barrel for 2019, and the 12-month average price for crude oil decreased from $65.56 per barrel for 2018 to $55.85 per barrel for 2019. The Company also experienced downward revisions of 90.2 Bcfe from a combination of working interest changes, optimization of well design in the current commodity price environment and well performance.

Subsequent to completion of estimates of proved reserves at December 31, 2019, management lowered its 2020 budgeted capital expenditures due to the expectation of continued depressed commodities pricing. All PUD locations in the

December 31, 2019 proved reserve estimates remained in the development plan and are scheduled to be drilled within five years from the time of initial booking. However, development of several PUD locations was delayed. Management analyzed the impact of the timing of development and determined total proved reserves was materially unchanged and the total PV-10 value of reserves decreased by approximately 0.5%. Management determined these changes were immaterial and did not adjust its estimates of proved reserves at December 31, 2019 for the impact of these timing changes.

In 2018, the Company experienced extensions and discoveries of 711.2 Bcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica Shale and SCOOP acreages. Of the total extensions and discoveries, 556.3 Bcfe was attributable to the addition of 75 PUD locations in the Utica field, 90.1 Bcfe was attributable to the addition of 11 PUD locations in the SCOOP field and 3.0 Bcfe was attributable to the addition of 13 PUD locations in the Southern Louisiana fields as a result of the Company's current development plan that refocused some activity within existing fields. This change reflects the Company's ongoing efforts to optimize the development program with well selection based on economic returns, commodity mix and surface considerations.

In 2018, the Company experienced downward revisions of 1.0 Tcfe in estimated proved reserves with the exclusion of 127 PUD locations in the Company's Utica field and 12 PUD locations in the Company's SCOOP field, which was primarily the result of changes in the Company's development schedule moving development in excess of five years from initial booking. The development plan change, as approved by the Company's senior management and board of directors, is a result of continued focus on free cash flow generation. This downward revision was partially offset by upward revisions of 82.4 Bcfe in estimated proved reserves in 2018 due to changes in wellbore lateral length, 67.6 Bcfe due to changes in ownership interest, 27.9 Bcfe due to an increase in pricing and 8.3 Bcfe due to changes in well performance. In addition, the Company sold approximately 44.9 Bcfe of proved undeveloped oil and natural gas reserves associated with various non-operated interests, the majority of which were in the Company's Utica field.

In 2017, the Company purchased 1.5 Tcfe through its 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 were 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 were operated by the Company and five of which were 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.

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, 2019, 2018 and 2017 using an unweighted average first-of-the-month price for the period January through December 31, 2019, 2018 and 2017.

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

	Year ended December 31,		
	2019	2018	2017
		(In thousands)	
Future cash flows	$ 10,451,179	$ 14,483,197	$ 11,202,692
Future development and abandonment costs	(2,058,374)	(2,437,853)	(3,005,217)
Future production costs	(4,512,940)	(5,067,554)	(2,152,821)
Future production taxes	(332,525)	(455,840)	(289,944)
Future income taxes	—	(943,293)	(573,965)
Future net cash flows	3,547,340	5,578,657	5,180,745
10% discount to reflect timing of cash flows	(1,843,753)	(2,595,932)	(2,537,181)
Standardized measure of discounted future net cash flows	$ 1,703,587	$ 2,982,725	$ 2,643,564
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	$ —	$ —	$ —

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

	Year ended December 31,		
	2019	2018	2017
	(In thousands)		
Sales and transfers of oil and gas produced, net of production costs	$ (734,354)	$ (1,063,215)	$ (756,257)
Net changes in prices, production costs, and development costs	(1,372,443)	590,519	913,714
Acquisition of oil and gas reserves in place	—	—	703,866
Extensions and discoveries	388,151	519,137	618,039
Previously estimated development costs incurred during the period	405,979	402,156	390,673
Revisions of previous quantity estimates, less related production costs	(321,397)	(356,933)	155,200
Sales of oil and gas reserves in place	(48,547)	(25,882)	—
Accretion of discount	298,273	264,356	68,804
Net changes in income taxes	424,628	(185,157)	(231,545)
Change in production rates and other	(319,428)	194,180	93,030
Total change in standardized measure of discounted future net cash flows	$ (1,279,138)	$ 339,161	$ 1,955,524

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	$ —	$ —	$ —
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	—	—	—
Revisions of previous quantity estimates, less related production costs	—	—	—
Accretion of discount	—	—	—
Net changes in income taxes	—	—	—
Change in production rates and other	—	—	—
Total change in standardized measure of discounted future net cash flows	$ —	$ —	$ —

20. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table summarizes quarterly financial data for the years endedDecember 31, 2019 and 2018:

	2019			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$ 320,578	$ 458,994	$ 285,175	$ 281,261
Income (loss) from operations	93,011	218,456	(570,955)	(1,444,205)
Income tax (benefit) expense	—	(179,331)	(144,047)	315,815
Net income (loss)	62,242	234,956	(484,802)	(1,814,754)
Income (loss) per share:				
Basic	$ 0.38	$ 1.47	$ (3.04)	$ (11.36)
Diluted	$ 0.38	$ 1.47	$ (3.04)	$ (11.36)

	2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$ 325,392	$ 252,740	$ 360,962	$ 415,950
Income from operations	111,990	15,373	115,116	156,480
Income tax benefit	(69)	—	—	—
Net income	90,090	111,319	95,150	134,001
Income per share:				
Basic	$ 0.50	$ 0.64	$ 0.55	$ 0.78
Diluted	$ 0.50	$ 0.64	$ 0.55	$ 0.78

21. SUBSEQUENT EVENTS

Sale of Water Infrastructure Assets

In December 2019, the Company entered into an agreement to divest its water infrastructure assets across its SCOOP position to a third-party water service provider. This transaction closed on January 2, 2020. The Company received $50.0 million in cash upon closing and has an opportunity to earn potential additional incentive payments over the next 15 years, subject to the Company's ability to meet certain thresholds which will be driven by, among other things, the Company's future development program and future water production levels. The agreement contains no minimum volume commitments. The assets related to this transaction are included in the amortization base of the full cost pool and the Company does not expect to recognize a gain or loss in the statement of operations.

Derivatives

In January and February 2020, the Company early terminated some of its fixed price swaps for natural gas scheduled to settle in August through November of 2020 covering an average of approximately 294,000 MMBtu of natural gas per day over this four month period. The value of these early terminations was used to enhance the fixed price for new natural gas swaps for April and May of 2020 covering an average of approximately 472,000 MMBtu of natural gas per day over this two month period at a weighted average price of $2.85 per MMBtu.

Debt Repurchases

In January 2020, the Company used borrowings under its revolving credit facility to repurchase in the open market approximately$10.2 million aggregate principal amount of its 2024 Notes, 2025 Notes, and 2026 Notes for $6.9 million.

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

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b). Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were not effective as of December 31, 2019 because of the material weakness in our internal control over financial reporting described in Management's Report on Internal Control Over Financial Reporting disclosed below.

Our Chief Executive Officer and Chief Financial Officer also determined that the material weakness existed at September 30, 2019 and also concluded that we did not maintain effective disclosure controls and procedures as of that date. Our Chief Executive Officer and Chief Financial Officer have concluded that the unaudited condensed consolidated financial statements included in the Form 10-Q filing for the reporting period ended September 30, 2019 were materially misstated as a result of the material weakness. The Company filed an amended Form 10-QA for the period ended September 30, 2019 with the restated amounts.

Remediation Plan for the Material Weakness

Our management is actively engaged in the planning for, and implementation of, remediation efforts to address the material weakness identified. Specifically, our management is currently evaluating our policies and procedures related to its process of accounting for unevaluated oil and gas properties. We plan to design and implement additional controls to ensure that we are properly and timely identifying and transferring leasehold costs associated with acreage expirations, lease transfers and proved reserve additions from the unevaluated capitalized cost pool to the evaluated amortization base. We will do that through continued focus on (i) redesigning controls over the completeness and reconciliation of acreage movements; (ii) identifying new resources to execute and monitor the redesigned controls; (iii) process enhancements and (iv) additional technical training of our accounting staff. Our management believes that these actions will remediate the material weakness in internal control over financial reporting described above. The material weakness will not be considered remediated until the controls operate for a sufficient period of time and management has concluded, through testing, that the controls are operating effectively.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2019, which materially affected, or were reasonably likely to materially affect, our internal control over financial reporting, other than the material weakness described above.

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.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis.

Management determined it did not effectively design and maintain controls over the completeness and accuracy of the accounting of transfers of unevaluated capitalized costs into the amortization base for the three and nine month periods ended September 30, 2019 and the twelve month period ended December 31, 2019. Specifically, we did not have an adequate process for monitoring that our accounting policies for transferring unevaluated oil and gas properties were consistently being performed timely and reconciled with the general ledger. This material weakness resulted in a material error in the amount of impairment expense booked in relation to our oil and gas properties for the nine months ended September 30, 2019 and resulted in the Company restating its consolidated financial statements as of and for the three and nine months ended September 30, 2019.

As a result of the material weakness in internal control over financial reporting described above, management has concluded that we did not maintain effective internal control over financial reporting as of December 31, 2019.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2019 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2019, as stated in their accompanying report.

/s/ David M. Wood		/s/ Quentin Hicks	
Name:	David M. Wood	Name:	Quentin Hicks
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, 2019, 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, because of the effect of the material weakness described in the following paragraphs on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by COSO.

A material weakness is a deficiency, or combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment:

The Company did not have effective internal control in place over the completeness and accuracy of the information used in determining the accounting for transfers of unevaluated capitalized costs into the amortization base.

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, 2019. The material weakness identified above was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2019 consolidated financial statements, and this report does not affect our report dated February 27, 2020 which 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 27, 2020

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The names of executive officers and certain other senior officers of the Company and their ages, titles and biographies as of the date hereof are incorporated by reference from Item 1 of Part I of this report. The other information called for by this Item 10 is incorporated herein by reference to the definitive proxy statement to be filed by Gulfport pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2020 (the 2020 Proxy Statement).

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item 11 is incorporated herein by reference to the 2020 Proxy Statement.

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

The information called for by this Item 12 is incorporated herein by reference to the 2020 Proxy Statement.

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

The information called for by this Item 13 is incorporated herein by reference to the 2020 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information called for by this Item 14 is incorporated herein by reference to the 2020 Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following financial statements, financial statement schedules and exhibits are filed as part of this report:

1. *Financial Statements.* Gulfport's consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules.* No financial statement schedules are applicable or required.
3. *Exhibits.* The exhibits listed below in the Index of Exhibits are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

INDEX OF EXHIBITS

		Incorporated by Reference				
Exhibit Number	Description	Form	SEC File Number	Exhibit	Filing Date	Filed or Furnished Herewith
3.1	Restated Certificate of Incorporation.	8-K	000-19514	3.1	4/26/2006	
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation.	10-Q	000-19514	3.2	11/6/2009	
3.3	Certificate of Amendment No. 2 to Restated Certificate of Incorporation.	8-K	000-19514	3.1	7/23/2013	
3.4	Second Amended and Restated Bylaws of Gulfport Energy Corporation.	8-K	000-19514	3.1	2/27/2020	
4.1	Form of Common Stock certificate.	SB-2	333-115396	4.1	7/22/2004	
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).	8-K	000-19514	4.1	4/21/2015	
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).	8-K	000-19514	4.1	10/19/2016	
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).	8-K	000-19514	4.1	12/21/2016	
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).	8-K	000-19514	4.1	10/11/2017	

4.6	Registration Rights Agreement, dated as of February 17, 2017, by and between Gulfport Energy Corporation and Vitruvian II Woodford, LLC.	8-K	000-19514	4.1	2/24/2017	
4.7	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.	8-K	000-19514	4.1	6/12/2015	
4.8	Description of Securities:Registered under Section 12(b) of the Exchange Act					X
10.1+	2019 Amended and Restated Stock Incentive Plan	DEF 14A	000-19514	Appendix A	4/30/19	
10.2+	2019 Amended and Restated Stock Incentive Plan Form of Performance Share Award Agreement.	8-K	000-19514	10.3	8/12/19	
10.3+	2014 Executive Annual Incentive Compensation Plan.	8-K	000-19514	10.1	4/7/2014	
10.4+	Form of Stock Option Agreement.	8-K	000-19514	10.2	4/26/2006	
10.5+	Form of Restricted Stock Award Agreement.	10-K	000-19514	10.3	2/28/2014	
10.6+	2013 Restated Stock Incentive Plan.	S-4	333-189992	10.1	7/17/2013	
10.7	Employment Agreement, entered into and effective as of August 1, 2019, by and between Gulfport Energy Corporation and David M. Wood.	10-Q	000-19514	10.3	8/2/2019	
10.8	Employment Agreement, entered into and effective as of August 1, 2019, by and between Gulfport Energy Corporation and Donnie Moore.	10-Q	000-19514	10.4	8/2/2019	
10.9	Employment Agreement, entered into and effective as of August 1, 2019, by and between Gulfport Energy Corporation and Patrick K. Craine.	10-Q	000-19514	10.5	8/2/2019	
10.10	Employment Agreement, effective as of August 26, 2019, by and between Gulfport Energy Corporation and Quentin Hicks.	8-K	000-19514	10.1	8/12/19	
10.11	Separation and Release Agreement, effective August 9, 2019, by and between Gulfport Energy Corporation and Keri Crowell.	8-K	000-19514	10.2	8/12/19	
10.12	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.	8-K	000-19514	10.1	1/3/2014	

10.13	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.	8-K	000-19514	10.1	4/28/2014
10.14	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.	8-K	000-19514	10.1	12/3/2014
10.15	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.	8-K	000-19514	10.1	4/15/2015
10.16	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.	10-Q	000-19514	10.2	8/7/2015
10.17	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.	8-K	000-19514	10.1	9/24/2015
10.18	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.	10-Q	000-19514	10.2	5/5/2016
10.19	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.	8-K	000-19514	10.1	12/15/2016
10.20	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.	8-K	000-19514	10.1	4/4/2017
10.21	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.	10-Q	000-19514	10.2	5/9/2017

10.22	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.	8-K	000-19514	10.1	10/5/2017
10.23	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.	8-K	000-19514	10.1	11/28/2017
10.24	Twelfth Amendment to Amended and Restated Credit Agreement, dated as of May 21, 2018, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto.	8-K	000-19514	10.1	5/25/2018
10.25	Thirteenth Amendment to the Amended and Restated Credit Agreement, dated as of November 28, 2018, between Gulfport Energy Corporation, as Borrower, The Bank of Nova Scotia, as Administrative Agent and the lenders party thereto.	8-K	000-19514	10.1	12/4/2018
10.26#	Sand Supply Agreement, effective as of October 1, 2014, by and between Muskie Proppant LLC and Gulfport Energy Corporation.	10-Q	000-19514	10.1	11/7/2014
10.27#	Amendment to Sand Supply Agreement, dated as of November 3, 2015, by and between Muskie Proppant LLC and Gulfport Energy Corporation.	10-Q	000-19514	10.2	11/5/2015
10.28	Second Amendment to Sand Supply Agreement, dated as of August 6, 2018, between Gulfport Energy Corporation and Muskie Proppant LLC.	10-Q	000-19514	10.2	11/1/2018
10.29#	Amended and Restated Master Services Agreement, effective as of October 1, 2014, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC.	10-Q	000-19514	10.2	11/7/2014
10.30#	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-K	000-19514	10.19	2/19/2016
10.31#	Amendment No. 2, dated as of July 10, 2018, between Stingray Pressure Pumping, LLC and Gulfport Energy Corporation to that certain Amended & Restated Master Services Agreement for Pressure Pumping Services, effective as of October 1, 2014, as amended effective January 1, 2016.	10-Q	000-19514	10.2	8/2/2018
10.32+	Form of Indemnification Agreement.	S-4	333-199905	10.1	11/6/2014
14	Code of Ethics.	8-K	000-19514	14	2/14/2006

21	Subsidiaries of the Registrant.	X
23.1	Consent of Grant Thornton LLP.	X
23.2	Consent of Netherland, Sewell & Associates, Inc.	X
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.	X
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.	X
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.	X
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.	X
99.1	Report of Netherland, Sewell & Associates, Inc.	X
101.INS	Inline XBRL Instance Document.	X
11.SCH*	Inline XBRL Taxonomy Extension Schema Document.	X
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.	X
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.	X
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document.	X
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.	X

* Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The registrant hereby undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

** The Company agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities and Exchange Commission upon request.

\+ Management contract, compensatory plan or arrangement.

\# Confidential treatment has been requested for portions of this exhibit. These portions have been omitted and submitted separately 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 27, 2020

GULFPORT ENERGY CORPORATION

By: /s/ Quentin Hicks

Quentin Hicks
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 27, 2020	By:	/s/ DAVID M. WOOD **David M. Wood** **Chief Executive Officer and President, Director** **(Principal Executive Officer)**
Date:	February 27, 2020	By:	/s/ DAVID L. HOUSTON **David L. Houston** **Chairman of the Board and Director**
Date:	February 27, 2020	By:	/s/ QUENTIN HICKS **Quentin Hicks** **Chief Financial Officer** **(Principal Accounting and Financial Officer)**
Date:	February 27, 2020	By:	/s/ DEBORAH G. ADAMS **Deborah G. Adams** **Director**
Date:	February 27, 2020	By:	/s/ ALVIN BLEDSOE **Alvin Bledsoe** **Director**
Date:	February 27, 2020	By:	/s/ VALERIE JOCHEN **Valerie Jochen** **Director**
Date:	February 27, 2020	By:	/s/ C. DOUG JOHNSON **C. Doug Johnson** **Director**
Date:	February 27, 2020	By:	/s/ BEN T. MORRIS **Ben T. Morris** **Director**
Date:	February 27, 2020	By:	/s/ PAUL WESTERMAN **Paul Westerman** **Director**

Exhibit 4.8

DESCRIPTION OF SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

As of [February 12], 2020, Gulfport Energy Corporation, a Delaware corporation (“Gulfport”), had one class of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended: common stock, par value $0.01 per share (“common stock”). The following contains a description of our common stock as well as certain related additional information. This description is a summary only and does not purport to be complete. We encourage you to read the complete text of Gulfport’s restated certificate of incorporation (the “certificate of incorporation”) and amended and restated bylaws (the “bylaws”), which we have filed or incorporated by reference as exhibits to Gulfport’s Annual Report on Form 10-K. References to “we,” “our” and “us” refer to Gulfport, unless the context otherwise requires. References to “stockholders” refer to holders of our common stock unless the context otherwise requires.

General

Pursuant to the certificate of incorporation, we have the authority to issue 205,000,000 shares of capital stock, consisting of 200,000,000 shares of our common stock and 5,000,000 shares of preferred stock, par value $0.01 per share.

Common Stock

Holders of our common stock are entitled to cast one vote for each share held of record on each matter submitted to a vote of stockholders. There is no cumulative voting for election of directors. Subject to the prior rights of any series of preferred stock which may from time to time be outstanding, if any, holders of our common stock are entitled to receive ratably dividends when, as and if declared by the board of directors out of funds legally available for such purpose and, upon the liquidation, dissolution or winding up of the company, are entitled to share ratably in all assets remaining after payment of liabilities and payment of accrued dividends and liquidation preferences on the preferred stock, if any. There are no redemption or sinking fund provisions that are applicable to our common stock. Subject only to the requirements of the Delaware General Corporation Law (the “DGCL”), the board of directors may issue shares of our common stock without stockholder approval, at any time and from time to time, to such persons and for such consideration as the board of directors deems appropriate. Holders of our common stock have no preemptive rights and have no rights to convert their common stock into any other securities. The outstanding common stock is validly authorized and issued, fully paid and nonassessable. Our common stock is traded on NASDAQ under the symbol “GPOR.”

Preferred Stock

Shares of preferred stock may be issued from time to time in one or more series as the board of directors may from time to time determine, each of said series to be distinctively designated. The voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations or restrictions thereof, 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 DGCL, the 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 of preferred stock.

The issuance of any such preferred stock could adversely affect the rights of the holders of our common stock and therefore, reduce the value of the common stock. The ability of the board of directors to issue preferred stock could discourage, delay, or prevent a takeover of us.

Anti-takeover Effects of Provisions of Our Certificate of Incorporation and Our Bylaws

Our certificate of incorporation, our bylaws and Delaware law contain provisions that may deter or render more difficult proposals to acquire control of us by means of a merger, tender offer, proxy contest or otherwise, or to remove our incumbent officers and directors. These provisions, summarized below, are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with our board of directors. We believe that the benefits of increased protection of our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging such proposals because negotiation of such proposals could result in an improvement of their terms.

Preferred stock. Our certificate of incorporation permits our board of directors to authorize and issue one or more series of preferred stock, which may render more difficult or discourage an attempt to change control of us by means of a merger, tender offer, proxy contest or otherwise. For example, if in the due exercise of its fiduciary obligations, the board of directors were to determine that a takeover proposal is not in our best interest, the board of directors could cause shares of preferred stock to be issued without stockholder approval in one or more private offerings or other transactions that might dilute the voting or other rights of the proposed acquirer or insurgent stockholder or stockholder group.

Stockholder meetings. Our bylaws provide that a special meeting of stockholders may be called only by the Chairman of the Board, the Chief Executive Officer or by a resolution adopted by a majority of the total number of directors the board of directors would have if there were no vacancies.

Requirements for advance notification of stockholder nominations and proposals. Our bylaws and certificate of incorporation establish advance notice procedures with respect to stockholder proposals and the nomination of candidates for election as directors, other than nominations made by or at the direction of the board of directors.

Stockholder Action By Written Consent. Our bylaws provide that, except as may otherwise be provided with respect to the rights of the holders of preferred stock, no action that is required or permitted to be taken by our stockholders at any annual or special meeting may be effected by written consent of stockholders in lieu of a meeting of stockholders, unless the action to be effected by written consent of stockholders and the taking of such action by such written consent have expressly been approved in advance by our board of directors. This provision, which may not be amended by our stockholders except by the affirmative vote of holders of at least 66-2/3% of the voting power of all then outstanding shares of capital stock entitled to vote generally in the election of directors, voting together as a single class, makes it difficult for stockholders to initiate or effect an action by written consent that is opposed by our board of directors.

Amendment of the bylaws. Under Delaware law, the power to adopt, amend, alter or repeal bylaws is conferred upon the stockholders. A corporation may, however, in its certificate of incorporation also confer upon the board of directors the power to adopt, amend or repeal its bylaws. Our certificate of incorporation and bylaws grant our board of directors the power to adopt, amend, alter or repeal our bylaws at any regular or special meeting of the board of director on the affirmative vote of a majority of the total number of directors the board of directors would have if there were no vacancies. Our stockholders may adopt, amend, alter or repeal our bylaws but only at any regular or special meeting of stockholders by an affirmative vote of holders of at least 66-2/3% of the voting power of all then outstanding shares of capital stock entitled to vote generally in the election of directors, voting together as a single class.

The provisions of our certificate of incorporation, our bylaws and Delaware law could have the effect of discouraging others from attempting hostile takeovers and, as a consequence, they may also inhibit temporary fluctuations in the market price of our common stock that often result from actual or rumored hostile takeover attempts. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish transactions which stockholders may otherwise deem to be in their best interests.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is Computershare Trust Company, N.A.

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
Mule Sky LLC	Delaware
GRUS, LLC	Oklahoma

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated February 27, 2020, 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, 2019. 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).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 27, 2020

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in the Form 10-K of Gulfport Energy Corporation (the "Form 10-K") of our report dated January 21, 2020 on oil and gas reserves of Gulfport Energy Corporation and its subsidiaries as of December 31, 2019 located in the United States 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 Form 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) and on Form S-3ASR (File No. 33-215078, automatically effective December 14, 2016, and File No. 333-217362, automatically effective April 18, 2017).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons

Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 27, 2020

Exhibit 31.1

CERTIFICATION

I, David M. Wood, Chief Executive Officer of Gulfport Energy Corporation, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 27, 2020

/s/ David M. Wood

David M. Wood
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION

I, Quentin Hicks, Chief Financial Officer of Gulfport Energy Corporation, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 27, 2020

/s/ Quentin Hicks

Quentin Hicks
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PERIODIC REPORT

I, David M. Wood, 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, 2019 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Dated: February 27, 2020

/s/ David M. Wood

David M. Wood

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, Quentin Hicks, 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, 2019 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

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

Dated: February 27, 2020

/s/ Quentin Hicks

Quentin Hicks

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

January 21, 2020

Mr. David M. Wood
Gulfport Energy Corporation
3001 Quail Springs Parkway
Oklahoma City, Oklahoma 73134

Dear Mr. Wood:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2019, to the Gulfport Energy Corporation (Gulfport) interest in certain oil and gas properties located in the United States. 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 all of the 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, 2019, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	7,361.9	29,096.5	1,739,457.7	2,047,424.5	1,360,106.4
Proved Developed Non-Producing	525.4	801.7	17,844.7	38,516.4	23,228.4
Proved Undeveloped	10,469.5	31,630.3	2,290,976.5	1,461,399.7	320,253.2
Total Proved	18,356.8	61,528.5	4,048,279.0	3,547,339.8	1,703,588.0

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. As requested, probable and possible reserves that exist for these 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 2019. For oil and NGL volumes, the average West Texas Intermediate spot price of $55.85 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.578 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 $51.72 per barrel of oil, $21.25 per barrel of NGL, and $2.024 per MCF of gas.

Operating costs used in this report are based on operating expense records of Gulfport. 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. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. The fees associated with Gulfport's transportation contracts are included as additional operating expenses. Headquarters general and administrative overhead expenses of Gulfport are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs 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.

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

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for 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: January 21, 2020	Date Signed: January 21, 2020

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 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

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

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

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

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

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

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

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

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

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

> *Supplemental definitions from the 2018 Petroleum Resources Management System:*
>
> *Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.*
>
> *Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that 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 that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. 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.

DEFINITIONS OF OIL AND GAS RESERVES

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

- (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

DEFINITIONS OF OIL AND GAS RESERVES

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

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

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

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

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

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

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

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

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

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

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

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

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

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

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

(20) *Production costs.*

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

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

(B) Repairs and maintenance.

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

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

(E) Severance taxes.

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

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

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

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

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

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

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

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

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

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an 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

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(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.

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

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

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

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

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

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

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

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

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

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

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

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

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

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

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