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

FORM 10-K

☑Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2019
or
☐Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission file number 001-31539

SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware	**41-0518430**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado	**80203**
(Address of principal executive offices)	(Zip Code)

(303) 861-8140
(Registrant's 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, $.01 par value	**SM**	**New York Stock Exchange**

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 (§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 emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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 for 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 Act). Yes ☐ No ☑

The aggregate market value of the 111,242,033 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the registrant's common stock on June 28, 2019, the last business day of the registrant's most recently completed second fiscal quarter, of $12.52 per share, as reported on the New York Stock Exchange, was $1,392,750,253. Shares of common stock held by each director and executive officer and by each person who owns 10 percent or more of the outstanding common stock or who is otherwise believed by the registrant to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 6, 2020, the registrant had 112,988,364 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required by Items 10, 11, 12, 13, and 14 of Part III is incorporated by reference from portions of the registrant's Definitive Proxy Statement on Schedule 14A relating to its 2020 annual meeting of stockholders to be filed within 120 days after December 31, 2019.

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Cautionary Information about Forward-Looking Statements

This Annual Report on Form 10-K (“Form 10-K”) contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical facts, included in this report that address activities, events, or developments with respect to our financial condition, results of operations, business prospects or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words “anticipate,” “assume,” “believe,” “budget,” “could,” “estimate,” “expect,” “forecast,” “intend,” “pending,” “plan,” “potential,” “project,” “target,” “will,” and similar expressions are intended to identify forward-looking statements. Forward-looking statements appear throughout this report, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- any changes to the borrowing base or aggregate lender commitments under our Sixth Amended and Restated Credit Agreement, as amended (the “Credit Agreement”);
- our outlook on future crude oil, natural gas, and natural gas liquids (also respectively referred to as “oil,” “gas,” and “NGLs” throughout this document) prices, well costs, service costs, lease operating costs, and general and administrative costs;
- the drilling of wells and other exploration and development activities, the ability to obtain permits and governmental approvals, and plans by us, our joint development partners, and/or other third-party operators;
- possible or expected acquisitions and divestitures, including the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- oil, gas, and NGL reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those reserve estimates;
- future oil, gas, and NGL production estimates, identified drilling locations, as well as drilling prospects, inventories, projects and programs;
- cash flows, anticipated liquidity, interest and related debt service expenses, changes in our effective tax rate, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, plans with respect to future dividend payments, and our outlook on our future financial condition or results of operations;
- plans, objectives, expectations and intentions; and
- other similar matters, such as those discussed in *Management’s Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Factors that may cause our financial condition, results of operations, business prospects or economic performance to differ from expectations include the factors discussed in Part I, Item 1A, *Risk Factors - Risks Related to Our Business* below and elsewhere in this report. The forward-looking statements in this report speak as of the filing of this report. Although, we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by applicable securities laws.

Glossary of Oil and Gas Terms

The oil and gas terms defined in this section are used throughout this report. The definitions of the terms developed reserves, exploratory well, field, proved reserves, and undeveloped reserves have been abbreviated from the respective definitions under Rule 4-10(a) of Regulation S-X. The entire definitions of those terms under Rule 4-10(a) of Regulation S-X can be located through the Securities and Exchange Commission’s (“SEC”) website at www.sec.gov.

Ad valorem tax. A tax based on the value of real estate or personal property.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil, NGLs, water, or other liquid hydrocarbons.

BBtu. One billion British thermal units.

Bcf. One billion cubic feet, used in reference to gas.

BOE. Barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas to one Bbl of oil or NGLs.

Btu. One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Developed reserves. Reserves 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.

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.

Dry hole. A well found to be incapable of producing either oil, gas, and/or NGLs in commercial quantities.

Exploratory well. 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.

Fee properties. The most extensive interest that can be owned in land, including surface and mineral (including oil and gas) rights.

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.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Gross acre. An acre in which a working interest is owned.

Gross well. A well in which a working interest is owned.

Horizontal wells. Wells that are drilled at angles greater than 70 degrees from vertical.

Lease operating expenses. The expenses incurred in the lifting of oil, gas, and/or NGLs from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition, drilling, or completion costs.

MBbl. One thousand barrels of oil, NGLs, water, or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet, used in reference to gas.

MMBbl. One million barrels of oil, NGLs, water, or other liquid hydrocarbons.

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet, used in reference to gas.

Net acres or net wells. Sum of our fractional working interests owned in gross acres or gross wells.

NGLs. The combination of ethane, propane, isobutane, normal butane, and natural gasoline that when removed from gas become liquid under various levels of higher pressure and lower temperature.

NYMEX WTI. New York Mercantile Exchange West Texas Intermediate, a common industry benchmark price for oil.

NYMEX Henry Hub. New York Mercantile Exchange Henry Hub, a common industry benchmark price for gas.

OPIS. Oil Price Information Service, a common industry benchmark for NGL pricing at Mont Belvieu, Texas.

PV-10 (Non-GAAP). PV-10 is a non-GAAP measure. The present value of estimated future revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, based on prices used in estimating the proved reserves and costs in effect as of the date indicated (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses, or depreciation, depletion, and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period.

Productive well. A well that is producing oil, gas, and/or NGLs or that is capable of commercial production of those products.

Proved reserves. Those quantities of oil, gas, and NGLs 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is 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.

Recompletion. The completion of an existing wellbore in a formation other than that in which the well has previously been completed.

Reserve life index. Expressed in years, represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil, gas, and/or associated liquid resources that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resource play. A term used to describe an accumulation of oil, gas, and/or associated liquid resources known to exist over a large areal expanse, which when compared to a conventional play typically has lower expected geological risk.

Royalty. The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from oil, gas, and NGLs produced and sold unencumbered by expenses relating to the drilling, completing, and operating of the affected well.

Royalty interest. An interest in an oil and gas property entitling the owner to shares of oil, gas, and NGL production free of costs of exploration, development, and production operations.

Seismic. The sending of energy waves or sound waves into the earth and analyzing the wave reflections to infer the type, size, shape, and depth of subsurface rock formations.

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

Standardized measure of discounted future net cash flows. The discounted future net cash flows related to estimated proved reserves based on prices used in estimating the reserves, year end costs, and statutory tax rates, at a 10 percent annual discount rate. The information for this calculation is included in *Supplemental Oil and Gas Information (unaudited)* located in Part II, Item 8 of this report.

Track record. Current year conversions of proved undeveloped reserves to proved developed reserves, divided by beginning of the year proved undeveloped reserves.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and NGLs regardless of whether such acreage contains estimated net proved reserves.

Undeveloped reserves. Reserves 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. The applicable SEC definition of undeveloped reserves provides that 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.

Working interest. The operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property and to share in the production, sales, and costs.

PART I

When we use the terms "SM Energy," the "Company," "we," "us," or "our," we are referring to SM Energy Company and its subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business in the *Glossary of Oil and Gas Terms* section of this report. Throughout this document we make statements and projections that address future expectations, possibilities, or events, all of which may be classified as "forward-looking." Please refer to the *Cautionary Information about Forward-Looking Statements* section of this report for an explanation of these types of statements and the associated risks and uncertainties.

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in the state of Texas. SM Energy was founded in 1908, incorporated in Delaware in 1915, and our initial public offering of common stock was in December 1992. Our common stock trades on the New York Stock Exchange under the ticker symbol "SM."

Our principal office is located at 1775 Sherman Street, Suite 1200, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Strategy

At SM Energy, our purpose is to make people's lives better by responsibly producing energy supplies, contributing to domestic energy security and prosperity, and having a positive impact in the communities where we live and work. Our long-term vision for the Company is to sustainably grow value for all of our stakeholders. We believe that in order to accomplish this vision, we must be a premier operator of top tier assets. Our current energy project development portfolio is focused on oil and gas producing properties in the state of Texas.

Significant Developments in 2019

Strategic Transformation. During 2019, we completed our strategic transformation, which commenced in 2016 through a series of asset acquisitions and divestitures. For the fourth quarter of 2019, we passed an important milestone by achieving a positive difference between our net cash provided by operating activities and our net cash used in investing activities. Our operational execution in 2019 was outstanding, achieving our objectives in important industry metrics, including key top-quartile benchmarks for environmental, health, and safety performance. We were also successful in proving up additional investment opportunities on our existing acreage positions.

Production. Our average daily production in 2019 consisted of 59.9 MBbl of oil, 300.8 MMcf of gas, and 22.2 MBbl of NGLs, for an average net daily equivalent production rate of 132.3 MBOE, which represented a 10 percent increase compared with 2018. This increase was primarily driven by a 25 percent increase in production volumes from our Midland Basin assets as a result of strong well performance, increased drilling and completion efficiencies, improved completion designs, and longer laterals. We completed more lateral feet in 2019 compared with 2018, driving continued increases in volumes at a lower average drilling and completion cost. On a retained asset basis, our production volumes increased 13 percent in 2019. As a result of the above, oil production revenue was approximately 75 percent of total production revenue for the year ended December 31, 2019, compared with 65 percent and 52 percent for the years ended December 31, 2018 and 2017, respectively. Please refer to *Areas of Operation* below for additional discussion.

Reserves and Capital Investment. Our estimated proved reserves decreased eight percent to 462.0 MMBOE at December 31, 2019, from 503.4 MMBOE at December 31, 2018. Reserve additions from discoveries, extensions, and infills totaled 98.4 MMBOE and were a result of our successful development programs, completion optimizations that resulted in improved well performance, and development plan improvements that we believe will enhance inventory value. The 2019 reserve additions were offset by 2019 production volumes of 48.3 MMBOE and by downward revisions of 94.7 MMBOE, which resulted primarily from the impact of lower commodity prices. Our proved reserve life index decreased to 9.6 years as of December 31, 2019, compared with 11.5 years as of December 31, 2018. Costs incurred for development and exploration activities, excluding acquisitions, decreased 23 percent from the prior year to $1.0 billion in 2019. Please refer to *Areas of Operation* and *Reserves* below, and to *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional discussion.

Net Cash Provided by Operating Activities. Net cash provided by operating activities was $823.6 million for the year ended December 31, 2019, compared with $720.6 million for the year ended December 31, 2018, which was an increase of 14 percent year-over-year. Oil, gas, and NGL production revenues decreased for the year ended December 31, 2019, compared with 2018, as the impact from higher production volumes was offset by lower commodity prices. However, the impact of lower commodity prices in 2019 was offset by a net derivative cash settlement gain of $39.2 million for the year ended December 31, 2019, compared to a net derivative cash settlement loss of $135.8 million for 2018. Please refer to *Analysis of Cash Flow Changes Between 2019 and 2018 and Between*

2018 and 2017 in *Overview of Liquidity and Capital Resources* in Part II, Item 7, and to *Note 10 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional discussion.

Outlook

Our business outlook for the next several years is a continuation of our trajectory of improving operating margins and cash flows while strengthening our balance sheet through absolute debt reduction and improved leverage metrics. Our total capital program in 2020, is budgeted to be between $825.0 million and $850.0 million, and is expected to be approximately 20% lower compared with 2019, in large part due to significant cost reductions and efficiencies that were achieved in 2019. Our 2020 program will be focused on highly economic oil development projects in both our Midland Basin and South Texas assets. We expect total production volumes in 2020 to decrease slightly compared with 2019 as expected continued growth in our oil production volumes will not completely offset expected decreases in gas and NGL production volumes.

Sustainability is a key focus of our plans, in terms of positioning ourselves financially to participate in future energy investment opportunities, and executing our strategy of being a premier operator with high standards for corporate responsibility. We are committed to exceptional safety, health, and environmental stewardship; supporting the professional development of a diverse and thriving team of employees; making a positive difference in the communities where we live and work; and transparency in reporting on our progress in these areas.

Please refer to *Overview of Liquidity and Capital Resources* in Part II, Item 7 of this report for discussion of how we expect to fund our 2020 capital program.

Areas of Operation

Our 2019 operations were concentrated in the Midland Basin and South Texas, as further described below. The following table summarizes estimated proved reserves, production, and costs incurred in oil and gas producing activities (“costs incurred”) for the year ended December 31, 2019, for these areas:

	Midland Basin	South Texas	Total (1)
Proved reserves			
Oil (MMBbl)	167.5	16.6	184.1
Gas (Bcf)	398.8	824.4	1,223.2
NGLs (MMBbl)	0.1	73.9	74.0
MMBOE (1)	234.1	227.8	462.0
Relative percentage	51%	49%	100%
Proved developed %	49%	58%	53%
Production			
Oil (MMBbl)	20.5	1.3	21.9
Gas (Bcf)	34.4	75.4	109.8
NGLs (MMBbl)	—	8.1	8.1
MMBOE (1)	26.3	22.0	48.3
Avg. daily equivalents (MBOE/d) (1)	72.0	60.3	132.3
Relative percentage	54%	46%	100%
Costs incurred (in millions) (2) (3)	$ 859.6	$ 160.9	$ 1,040.2

(1) Amounts may not calculate due to rounding.
(2) Regional costs incurred do not sum to total costs incurred due primarily to corporate overhead charges incurred on exploration activities that are excluded from this regional table. Please refer to *Costs Incurred in Oil and Gas Producing Activities* in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.
(3) Costs incurred for 2019 included $11.3 million related to acquisitions of primarily unproved oil and gas properties in the Midland Basin. Please refer to *Costs Incurred in Oil and Gas Producing Activities* in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.

Excluding acquisition activity, costs incurred decreased in 2019 by 23 percent compared with 2018 primarily due to increased operational efficiencies and decreased drilling, completion crew, and sand costs incurred in developing our Midland Basin assets. Total estimated proved reserves at year end 2019 decreased eight percent from 2018. Production increased 10 percent on an equivalent basis for the year ended December 31, 2019, compared with 2018, and increased 13 percent on a retained assets basis.

Midland Basin. Our Midland Basin assets are located within the Permian Basin in Western Texas and are comprised of approximately 80,000 net acres ("Midland Basin"). In 2019, we focused on continuing to delineate, develop, and expand our Midland Basin position. Our current Midland Basin position provides substantial future development opportunities within multiple oil-rich intervals, including the Spraberry and Wolfcamp formations.

In 2019, we incurred $859.6 million of costs and averaged six drilling rigs and three completion crews. The majority of our Midland Basin capital was deployed on projects targeting the Lower Spraberry and Wolfcamp A and B intervals on our RockStar assets in Howard and Martin Counties, Texas and Sweetie Peck assets in Upton and Midland Counties, Texas. We completed 123 gross (111 net) wells and full-year production increased 25 percent year-over-year to 26.3 MMBOE for 2019. As of December 31, 2019, there were 51 gross (48 net) wells that had been drilled but not completed in our Midland Basin program. Estimated proved reserves increased nine percent to 234.1 MMBOE at year end 2019, from 214.3 MMBOE at year end 2018. This increase was driven by additions of 58.9 MMBOE from discoveries, extensions and infill, and acquisitions, partially offset by 12.6 MMBOE of downward revisions from price, performance, and aged proved undeveloped reserves.

South Texas. Our South Texas assets are comprised of approximately 158,900 net acres located in Dimmit and Webb Counties, Texas ("South Texas"). Our current operations in South Texas are focused on developing the Eagle Ford shale formation and delineating the Austin Chalk formation. Our overlapping acreage position in the Eagle Ford shale and Austin Chalk formations covers a significant portion of the western Eagle Ford shale and Maverick Basin Austin Chalk ("Eagle Ford shale") and includes acreage across the oil, gas-condensate, and dry gas windows with gas composition amenable to processing for NGL extraction.

In 2019, we incurred $160.9 million of costs and averaged one drilling rig and one completion crew. We completed 31 gross (20 net) wells during 2019, and full-year regional production increased one percent year-over-year to 22.0 MMBOE for 2019. As of December 31, 2019, there were 21 gross (21 net) wells that had been drilled but not completed in our South Texas program.

Certain drilling and completion activities in the northern portion of our South Texas acreage position were primarily funded by a third party pursuant to our joint development agreement. The agreement provided that the third party carried substantially all drilling and completion costs and receives a majority of the working and revenue interest in these wells until certain payout thresholds are reached. This arrangement allowed us to leverage third-party capital to prove up the value of our Eagle Ford North area, while also allowing us to test cutting edge technology, capture additional technical data, satisfy certain lease obligations, and potentially expand economic drilling inventory in the future. All wells subject to this agreement were drilled and completed as of December 31, 2019.

During 2019, we added 43.0 MMBOE of estimated proved reserves, offset by downward revisions of 82.1 MMBOE, of which 68.5 MMBOE resulted from decreased commodity pricing and 10.3 MMBOE resulted from performance revisions. As a result, estimated proved reserves decreased 21 percent to 227.8 MMBOE at year end 2019, from 289.1 MMBOE at year end 2018.

Reserves

Reserve estimates are inherently imprecise and estimates for new discoveries and undeveloped locations are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, we expect these estimates to change as new information becomes available. The following table presents the standardized measure of discounted future net cash flows and pre-tax PV-10 ("PV-10"). PV-10 is a non-GAAP financial measure, and generally differs from the standardized measure of discounted future net cash flows, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither the standardized measure of discounted future net cash flows nor PV-10 represents the fair market value of our oil and gas properties. We and others in the oil and gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held without regard to the specific tax characteristics of such entities. Please refer to the *Glossary of Oil and Gas Terms* section of this report for additional information regarding these measures and refer to the reconciliation of the standardized measure of discounted future net cash flows to PV-10 set forth below. The actual quantities and present value of our estimated proved reserves may be more or less than we have estimated. No estimates of our proved reserves have been filed with or included in reports to any federal authority or agency, other than the SEC, since the beginning of the last fiscal year. The following table should be read along with the section entitled *Risk Factors – Risks Related to Our Business* below.

Our ability to replace production with new oil and gas reserves is critical to the future success of our business. Please refer to the reserve life index term in the *Glossary of Oil and Gas Terms* section of this report for information describing how this metric is calculated.

The following table summarizes estimated proved reserves, the standardized measure of discounted future net cash flows (GAAP), PV-10 (non-GAAP), the prices used in the calculation of proved reserves estimates, and reserve life index as of December 31, 2019, 2018, and 2017:

	As of December 31,		
	2019	2018	2017
Reserve data:			
Proved developed			
Oil (MMBbl)	85.0	68.2	58.6
Gas (Bcf)	712.1	699.1	642.9
NGLs (MMBbl)	43.4	60.1	49.0
MMBOE (1)	247.0	244.8	214.7
Proved undeveloped			
Oil (MMBbl)	99.1	107.6	99.6
Gas (Bcf)	511.1	622.7	637.2
NGLs (MMBbl)	30.6	47.2	47.6
MMBOE (1)	214.9	258.6	253.4
Total proved (1)			
Oil (MMBbl)	184.1	175.7	158.2
Gas (Bcf) (2)	1,223.2	1,321.8	1,280.1
NGLs (MMBbl)	74.0	107.4	96.5
MMBOE	462.0	503.4	468.1
Proved developed reserves %	53%	49%	46%
Proved undeveloped reserves %	47%	51%	54%
Reserve data (in millions):			
Standardized measure of discounted future net cash flows (GAAP)	$ 4,104.0	$ 4,654.4	$ 3,024.1
PV-10 (non-GAAP):			
Proved developed PV-10	$ 2,830.4	$ 3,084.2	$ 1,984.2
Proved undeveloped PV-10	1,532.4	2,020.1	1,072.3
Total proved PV-10 (non-GAAP)	$ 4,362.8	$ 5,104.3	$ 3,056.5
12-month trailing average prices (3)			
Oil (per Bbl)	$ 55.69	$ 65.56	$ 51.34
Gas (per MMBtu)	$ 2.58	$ 3.10	$ 3.00
NGLs (per Bbl)	$ 22.68	$ 33.45	$ 27.69
Reserve life index (years)	9.6	11.5	10.5

(1) Amounts may not calculate due to rounding.
(2) For the years ended December 31, 2019, 2018, and 2017, proved gas reserves contained 44.9 Bcf, 59.1 Bcf, and 48.1 Bcf of gas, respectively, that we expect to produce and use as a field equipment fuel source (primarily to power compressors).
(3) The prices used in the calculation of proved reserve estimates reflect the 12-month average of the first-day-of-the-month prices in accordance with SEC rules. We then adjust these prices to reflect appropriate quality and location differentials over the period in estimating our proved reserves.

The following table reconciles the standardized measure of discounted future net cash flows (GAAP) to the PV-10 (non-GAAP) of total estimated proved reserves. Please refer to the *Glossary of Oil and Gas Terms* section of this report for the definitions of standardized measure of discounted future net cash flows and PV-10.

	As of December 31,		
	2019	2018	2017
	(in millions)		
Standardized measure of discounted future net cash flows (GAAP)	$ 4,104.0	$ 4,654.4	$ 3,024.1
Add: 10 percent annual discount, net of income taxes	2,955.3	3,847.1	2,573.2
Add: future undiscounted income taxes	579.8	1,012.2	205.7
Pre-tax undiscounted future net cash flows	7,639.1	9,513.7	5,803.0
Less: 10 percent annual discount without tax effect	(3,276.3)	(4,409.4)	(2,746.5)
PV-10 (non-GAAP)	$ 4,362.8	$ 5,104.3	$ 3,056.5

Proved Undeveloped Reserves

Proved undeveloped reserves include those reserves that are expected to be recovered from future wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. As of December 31, 2019, we did not have any proved undeveloped reserves that had been on our books in excess of five years, and none of our proved undeveloped reserves were on acreage expected to expire or on acreage that was not expected to be held through renewal before the targeted completion date.

For proved undeveloped locations that are more than one development spacing area from developed producing locations, we utilized reliable geologic and engineering technology when booking estimated proved undeveloped reserves. Of the 214.9 MMBOE of total proved undeveloped reserves as of December 31, 2019, approximately 60.1 MMBOE of proved undeveloped reserves in the Midland Basin and 68.7 MMBOE of proved undeveloped reserves in our South Texas position were offset by more than one development spacing area from the nearest developed producing location. We incorporated public and proprietary data from multiple sources to establish geologic continuity of each formation and their producing properties. This included seismic data and interpretations (3-D and micro seismic), open hole log information (both vertically and horizontally collected) and petrophysical analysis of that log data, mud logs, gas sample analysis, measurements of total organic content, thermal maturity, test production, fluid properties, and core data as well as statistical performance data yielding predictable and repeatable reserve estimates within certain analogous areas. These locations were limited to only those areas where both established geologic consistency and sufficient statistical performance data could be demonstrated to provide reasonably certain results. In all other areas, we restricted proved undeveloped locations to development spacing areas that are immediately adjacent to developed spacing areas.

As of December 31, 2019, estimated proved undeveloped reserves decreased 43.7 MMBOE, or 17 percent compared with December 31, 2018. The following table provides a reconciliation of our proved undeveloped reserves for the year ended December 31, 2019:

	Total (MMBOE)
Total proved undeveloped reserves:	
Beginning of year	258.6
Revisions of previous estimates	(47.6)
Additions from discoveries, extensions, and infill	78.5
Purchases of minerals in place	1.9
Removed for five-year rule	(9.8)
Conversions to proved developed	(66.7)
End of year	214.9

Revisions of previous estimates. Revisions of previous estimates includes a downward pricing revision of 42.3 MMBOE from our South Texas program as a result of decreased gas and NGL prices. In addition, we had downward performance revisions of 6.0 MMBOE in our Midland Basin program as we updated certain assumptions based on future well spacing.

Additions from discoveries, extensions, and infill. We added 40.8 MMBOE and 30.4 MMBOE of infill estimated proved undeveloped reserves in our Midland Basin and South Texas assets, respectively, in 2019. We added an additional 3.1 MMBOE and 4.1 MMBOE of estimated proved undeveloped reserves in the Midland Basin and South Texas, respectively, through various extensions and discoveries. The majority of additions in our Midland Basin and South Texas programs resulted from future development projects identified by our on-going development and portfolio optimization activities.

Removed for five-year rule. As a result of our testing and delineation efforts in 2019, we revised certain aspects of our future development plans to focus on maximizing returns and the value of our assets. As a result, we removed 9.8 MMBOE of estimated proved undeveloped reserves and reclassified these locations to unproved reserve categories. The reclassified locations were generally replaced by locations with higher quality proved undeveloped reserves, which are reflected as additions from discoveries, extensions, and infill.

Conversions to proved developed. Our 2019 conversion rate was 26 percent. During 2019, we incurred $686.3 million on projects with reserves booked as proved undeveloped at the end of 2018, of which $611.1 million was spent on converting proved undeveloped reserves to proved developed reserves by December 31, 2019. At December 31, 2019, drilled but not completed wells represented 26.8 MMBOE of total estimated proved undeveloped reserves. We expect to incur $182.0 million of capital expenditures in completing these drilled but not completed wells, and we expect all estimated proved undeveloped reserves to be converted to proved developed reserves within five years from their initial booking as proved undeveloped reserves.

As of December 31, 2019, estimated future development costs relating to our proved undeveloped reserves were $591.5 million, $615.6 million, and $458.1 million in 2020, 2021, and 2022, respectively.

Internal Controls Over Proved Reserves Estimates

Our internal controls over the recording of proved reserves are structured to objectively and accurately estimate our reserve quantities and values in compliance with the SEC’s regulations. Our process for managing and monitoring our proved reserves is delegated to our corporate reserves group and is coordinated by our Corporate Engineering Manager, subject to the oversight of our management and the Audit Committee of our Board of Directors, as discussed below. Our Corporate Engineering Manager has approximately 12 years of experience in the energy industry and has been employed by the Company for 10 years. He holds a Bachelor of Science Degree in Petroleum Engineering from Montana Tech of the University of Montana and is a Registered Professional Petroleum Engineer in the states of Texas, Wyoming and Montana. He is also a member of the Society of Petroleum Engineers. Technical, geological, and engineering reviews of our assets are performed throughout the year by our regional staff. Data, obtained from these reviews, in conjunction with economic data and our ownership information, is used in making a determination of estimated proved reserve quantities. Our regional engineering technical staff do not report directly to our Corporate Engineering Manager; they report to either their respective regional technical managers or directly to the regional manager. This design is intended to promote objective and independent analysis within our regions in the proved reserves estimation process.

Third-party Reserves Audit

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum engineering consulting services throughout the world for over 70 years. Ryder Scott performed an independent audit using its own engineering assumptions, but with economic and ownership data we provided. Ryder Scott audits a minimum of 80 percent of our total calculated proved reserve PV-10. In the aggregate, the proved reserve amounts of our audited properties determined by Ryder Scott are required, per our policy, to be within 10 percent of our proved reserve amounts for the total Company, as well as for each respective region. The technical person at Ryder Scott primarily responsible for overseeing our reserves audit is an Advising Senior Vice President who received a Bachelor of Science degree in Chemical Engineering from Purdue University in 1979 and a Master of Science degree in Chemical Engineering from the University of California, Berkeley, in 1981. He is a licensed Professional Engineer in the State of Texas and a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. The 2019 Ryder Scott report concerning our reserves is included as Exhibit 99.1.

In addition to a third-party audit, our reserves are reviewed by our management with the Audit Committee of our Board of Directors. Our management, which includes our President and Chief Executive Officer, Executive Vice President and Chief Financial Officer, and Executive Vice President and Chief Operating Officer, is responsible for reviewing and verifying that the estimate of proved reserves is reasonable, complete, and accurate. The Audit Committee reviews a summary of the final reserves estimate in conjunction with Ryder Scott’s results and also meets with Ryder Scott representatives, apart from our management, from time to time to discuss processes and findings.

Production

The following table summarizes the volumes and realized prices of oil, gas, and NGLs produced and sold from properties in which we held an interest during the periods presented. Realized prices presented below exclude the effects of derivative contract settlements. Also presented is a summary of related production expense on a per BOE basis.

	For the Years Ended December 31,		
	2019	2018	2017
Net production volumes			
Oil (MMBbl)	21.9	18.8	13.7
Gas (Bcf)	109.8	103.2	123.0
NGLs (MMBbl)	8.1	7.9	10.3
Equivalent (MMBOE) [1]	48.3	43.9	44.5
Midland Basin net production volumes [2]			
Oil (MMBbl)	20.5	16.6	8.5
Gas (Bcf)	34.4	25.8	14.7
NGLs (MMBbl)	—	—	—
Equivalent (MMBOE) [1]	26.3	20.9	11.0
Eagle Ford shale net production volumes [2][3]			
Oil (MMBbl)	1.3	1.2	1.9
Gas (Bcf)	75.4	76.1	104.0
NGLs (MMBbl)	8.1	7.9	10.1
Equivalent (MMBOE) [1]	21.9	21.8	29.3
Realized price, before the effect of derivative settlements			
Oil (per Bbl)	$ 54.10	$ 56.80	$ 47.88
Gas (per Mcf)	$ 2.39	$ 3.43	$ 3.00
NGLs (per Bbl)	$ 17.26	$ 27.22	$ 22.35
Per BOE	$ 32.84	$ 37.27	$ 28.20
Production expense per BOE			
Lease operating expense	$ 4.67	$ 4.74	$ 4.43
Transportation costs	$ 3.88	$ 4.36	$ 5.48
Production taxes	$ 1.35	$ 1.52	$ 1.18
Ad valorem tax expense	$ 0.48	$ 0.48	$ 0.34

(1) Amounts may not calculate due to rounding.
(2) For each of the years ended December 31, 2019, 2018, and 2017, total estimated proved reserves attributed to our Midland Basin assets and our Eagle Ford shale assets exceeded 15 percent of our total estimated proved reserves expressed on an equivalent basis.
(3) During the first quarter of 2017, we completed the divestiture of our outside-operated Eagle Ford shale assets. These assets represented approximately 1.5 MMBOE of net production on an equivalent basis for the year ended December 31, 2017.

Productive Wells

As of December 31, 2019, we had working interests in 807 gross (758 net) productive oil wells and 519 gross (487 net) productive gas wells. Productive wells are exploratory, development, or extension wells that are producing, or are capable of commercial production of oil, gas, and/or NGLs. Productive wells may be temporarily shut-in. Multiple completions in the same wellbore are counted as one well. As of December 31, 2019, two of these wells had multiple completions. A well is categorized under state reporting regulations as an oil well or a gas well based on the ratio of gas to oil when it first commenced production, but such designation may not be indicative of current or future production composition.

Drilling and Completion Activity

All of our drilling and completion activities are conducted by independent contractors. We do not own any drilling or completion equipment. The following table summarizes the number of operated and outside-operated wells drilled and completed or recompleted on our properties in 2019, 2018, and 2017, excluding non-consented projects, active injector wells, salt water disposal wells, or wells in which we own only a royalty interest:

	For the Years Ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Oil	119	107	103	92	56	46
Gas	27	16	39	24	38	35
Non-productive	1	1	—	—	4	3
	147	124	142	116	98	84
Exploratory wells						
Oil	4	4	18	14	32	29
Gas	4	4	1	1	—	—
Non-productive	1	1	—	—	1	—
	9	9	19	15	33	29
Total	156	133	161	131	131	113

A productive well is an exploratory, development, or extension well that is producing or is capable of commercial production of oil, gas, and/or NGLs. A non-productive well, frequently referred to within the industry as a dry hole, is an exploratory, development, or extension well that proves to be incapable of producing oil, gas, and/or NGLs in sufficient commercial quantities to justify completion, or upon completion, the economic operation of a well.

As defined by the SEC, 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. A development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of equipment for production of oil, gas, and/or NGLs, or in the case of a dry hole, the reporting to the appropriate authority that the well has been abandoned.

In addition to the wells drilled and completed in 2019 (included in the table above), we were actively participating in the drilling of 22 gross (20 net) wells and had 66 gross (63 net) drilled but not completed wells as of January 31, 2020. These drilled but not completed wells represent wells that were being completed or were waiting on completion as of January 31, 2020.

Acreage

The following table sets forth the number of gross and net surface acres of developed and undeveloped oil and gas leasehold, fee properties, and mineral servitudes that we held as of December 31, 2019. Undeveloped acreage includes leasehold interests containing proved undeveloped reserves.

	Developed Acres (1)		Undeveloped Acres (2)(3)		Total	
	Gross	Net	Gross	Net	Gross	Net
Midland Basin:						
RockStar	67,113	59,589	4,966	4,217	72,079	63,806
Sweetie Peck	17,007	15,782	2,835	251	19,842	16,033
Midland Basin Total (4)	84,120	75,371	7,801	4,468	91,921	79,839
Eagle Ford shale	74,247	71,296	88,058	87,631	162,305	158,927
Other (5)	16,259	11,363	90,415	25,599	106,674	36,962
Total	174,626	158,030	186,274	117,698	360,900	275,728

(1) Developed acreage is acreage assigned to producing wells for the state approved spacing unit for the producing formation. Our developed acreage that includes multiple formations with different well spacing requirements may be considered undeveloped for certain formations but has been included only as developed acreage in the table above.

(2) Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and/or NGLs regardless of whether such acreage contains estimated net proved reserves.

(3) As of February 6, 2020, approximately 1,354, 184, and 155 net acres of undeveloped acreage are scheduled to expire by December 31, 2020, 2021, and 2022, respectively, if production is not established or we take no other action to extend the terms of the applicable leases. Certain of our Eagle Ford shale acreage is subject to lease consolidation agreements containing drilling, completion, and other obligations that we currently intend to satisfy. Failure to meet these obligations results in termination of the lease consolidation agreements, which could result in additional future lease expirations if continuous development obligations required by individual leases are not met.

(4) As of December 31, 2019, total Midland Basin acreage excludes approximately 1,940 net acres associated with drill-to-earn opportunities that we intend to pursue.

(5) Includes other non-core acreage located in Louisiana, Montana, North Dakota, Texas, Utah, and Wyoming.

Delivery Commitments

As of December 31, 2019, we had gathering, processing, transportation throughput, and delivery commitments with various third-parties that require delivery of a minimum quantity of 24 MMBbl of oil and 424 Bcf of gas through 2023, and 18 MMBbl of produced water through 2027. We are required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments under certain agreements. We expect to fulfill our delivery commitments from a combination of production from our existing productive wells, future development of our proved undeveloped reserves, and future development of resources not yet characterized as proved reserves. Under certain of our commitments, if we are unable to deliver the minimum quantity from our production, we may deliver production acquired from third-parties to satisfy our minimum volume commitments.

As of December 31, 2019, in the event that no additional volumes are delivered in accordance with these agreements, the aggregate undiscounted future deficiency payments would total $218.5 million. This amount does not include deficiency payment estimates associated with approximately 16.5 MMBbl of future oil delivery commitments where we cannot predict with accuracy the amount and timing of these payments, as such payments are dependent upon the price of oil in effect at the time of settlement.

As of the filing of this report, we do not expect to incur any material shortfalls with regard to these commitments.

Major Customers

We do not believe the loss of any single purchaser of our production would materially impact our operating results, as oil, gas, and NGLs are products with well-established markets and other viable purchaser options are available in our operating regions.

The following major customers and entities under common control accounted for 10 percent or more of our total oil, gas, and NGL production revenue for at least one of the periods presented:

	For the Years Ended December 31,		
	2019	2018	2017
Major customer #1 (1)	18%	18%	6%
Major customer #2 (1)	14%	5%	1%
Major customer #3 (1)	13%	7%	—%
Major customer #4 (1)	9%	10%	10%
Group #1 of entities under common control (2)	13%	18%	17%
Group #2 of entities under common control (2)	11%	12%	8%

(1) These major customers are purchasers of a portion of our production from our Midland Basin assets.
(2) In the aggregate, these groups of entities under common control represented purchasers of more than 10 percent of total oil, gas, and NGL production revenue for at least one of the periods presented; however, no individual entity comprising either group was a purchaser of more than 10 percent of our total oil, gas, and NGL production revenue.

Employees and Office Space

As of February 6, 2020, we had 530 full-time employees. This is a 13 percent decrease from the 611 full-time employees that we reported as of February 7, 2019. None of our employees are subject to a collective bargaining agreement.

The following table summarizes the approximate square footage of office space leased by us, as of December 31, 2019, including our corporate headquarters and regional offices:

	Approximate Square Footage Leased
Corporate	107,000
Midland Basin	59,000
South Texas	62,000
Total	228,000

In addition to the leased office space summarized in the table above, as of December 31, 2019, we owned approximately 12,000 square feet of office space in South Texas.

Title to Properties

Substantially all of our oil and gas producing assets are held pursuant to oil and gas leases from third-party mineral owners. We obtain title opinions prior to commencing initial drilling operations on the properties we operate. We have obtained title opinions or have conducted other title review on substantially all of our producing properties and believe we have satisfactory title to such properties. Most of our producing properties are subject to mortgages securing indebtedness under our Credit Agreement, royalty and overriding royalty interests, liens for current taxes, and other ordinary course burdens that we believe do not materially interfere with the development of such properties. We typically perform title investigation in accordance with standards generally accepted in the oil and gas industry before acquiring developed and undeveloped leasehold acreage.

Seasonality

The price of crude oil is primarily driven by global socioeconomic factors and is less affected by seasonal fluctuations; however, demand for energy is generally higher in the winter and the summer driving season. The demand and price for gas frequently increases during winter months and decreases during summer months. To lessen the impact of seasonal gas demand and price fluctuations, pipelines, utilities, local distribution companies, and industrial users regularly utilize gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can divert gas that is traditionally placed into storage which, in turn, may increase the typical winter seasonal price. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations.

Certain of our drilling, completion, and other operations are also subject to seasonal limitations. Seasonal weather conditions, government regulations, and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate. Please refer to *Risk Factors - Risks Related to Our Business* below for additional discussion.

Competition

The oil and gas industry is intensely competitive, particularly with respect to acquiring prospective oil and gas properties. We believe our acreage positions provide a foundation for development activities that we expect to fuel our future growth. Our competitive position also depends on our geological, geophysical, and engineering expertise, as well as our financial resources. We believe the location of our acreage; our exploration, drilling, operational, and production expertise; available technologies; our financial resources and expertise; and the experience and knowledge of our management and technical teams enable us to compete in our core operating areas. However, we face intense competition from a substantial number of major and independent oil and gas companies, which in some cases have larger technical teams and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and gas reserves, but also have gathering, processing or refining operations, market refined products, provide, dispose of and transport fresh and produced water, own drilling rigs or production equipment, or generate electricity.

We also compete with other oil and gas companies in securing drilling rigs and other equipment and services necessary for the drilling, completion, and maintenance of wells, as well as for the gathering, transporting, and processing of oil, gas, NGLs and water. Consequently, we may face shortages, delays, or increased costs in securing these services from time to time. The oil and gas industry also faces competition from alternative fuel sources, including renewable energy sources such as solar and wind-generated energy, and other fossil fuels such as coal. Competitive conditions may be affected by future energy, climate-related, financial, or other policies, legislation, and regulations.

In addition, we compete for people, including experienced geologists, geophysicists, engineers, and other professionals. Throughout the oil and gas industry, the need to attract and retain talented people has grown at a time when the availability of individuals with these skills is becoming more limited due to the evolving demographics of our industry. We are not insulated from competition for quality people, and we must compete effectively in order to be successful.

Government Regulations

Nearly every aspect of our business is subject to expansive federal, state, and local laws and governmental regulations. These laws and regulations frequently change in response to economic or political conditions, or other developments, and our regulatory burden may increase in the future. Laws and regulations have the potential to increase our cost of doing business and consequently could affect our profitability. However, we do not believe that we are affected to a materially greater or lesser extent than others in our industry.

Energy Regulations

Texas, the state where we conduct operations and own nearly all of our oil and gas assets, has adopted laws and regulations governing the exploration for and production of oil, gas, and NGLs, including laws and regulations requiring permits for the drilling of wells, imposing bond requirements in order to drill or operate wells, governing the timing of drilling and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Our operations are also subject to Texas conservation laws and regulations, including regulations governing the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, the spacing of wells, and the unitization or pooling of oil and gas properties. In addition, Texas conservation laws establish maximum rates of production from oil and gas wells, generally limit or prohibit the venting or flaring of gas, and may impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Our sales of gas are affected by the availability, terms, and cost of gas pipeline transportation. The Federal Energy Regulatory Commission ("FERC") has jurisdiction over the transportation and sale for resale of gas in interstate commerce. FERC's current regulatory framework generally provides for a competitive and open access market for sales and transportation of gas. However, FERC regulations continue to affect the midstream and transportation segments of the industry, and thus can indirectly affect the sales prices we receive for gas production.

Environmental, Health and Safety Matters

General. Our operations are subject to stringent and complex federal, state, and local laws and regulations governing protection of the environment and worker health and safety as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, including areas containing certain wildlife or threatened and endangered plant and animal species; and

- require remedial measures to mitigate pollution from former and ongoing operations, such as closing pits and plugging abandoned wells.

These laws, rules, and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes may result in more stringent, or different permitting, waste handling, disposal, and cleanup requirements for the oil and gas industry and could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules, and regulations to which our business is subject.

Waste handling. The Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency (“EPA”), individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced water, and most of the other wastes associated with the exploration, development, and production of oil or gas are currently regulated under RCRA’s non-hazardous waste provisions. However, it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation, and Liability Act. The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release or threatened release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and gas exploration and production for many years. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third-parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, pay fines, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (“Clean Water Act”) and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States and states. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, or analogous state agencies. The Clean Water Act also prohibits discharge of dredged or fill material into waters of the United States, including wetlands, except in accordance with the terms of a permit issued by the United States Army Corps of Engineers, or a state if the state has assumed authority to issue such permits. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990 (“OPA”) addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in governmental penalties and civil liability.

Air emissions. The federal Clean Air Act (“CAA”) and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other “greenhouse gases” (“GHG”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA began adopting and implementing a comprehensive suite of regulations to restrict emissions of GHGs under existing provisions of the CAA. The Trump administration has taken steps to rescind or review many of these regulations. Legislative and regulatory initiatives related to climate change could have an adverse effect on our operations and the demand for oil and gas. Please refer to *Risk Factors - Risks Related to Our Business - Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil, gas, and NGLs.* In addition to the effects of regulation, the meteorological effects of global climate change could pose additional risks to our operations, including physical damage risks associated with more frequent, more intensive storms and flooding, and could adversely affect the demand for our products.

Endangered species. The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts on protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on these species. It is also possible that a federal or state agency could order a complete halt to activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling, completion, and production activities could impair our ability to timely complete well drilling and development and could adversely affect our future production from those areas.

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment to determine the potential direct, indirect, and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. The Trump administration has taken steps to modify NEPA's implementing regulations intended to streamline the NEPA process. No new regulations have yet been finalized. Judicial and regulatory challenges are expected, and we cannot predict the outcome of any such challenges. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits subject to the requirements of NEPA. This process has the potential to delay development of some of our oil and gas projects.

OSHA and other laws and regulations. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in most of our drilling and completion programs. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program. The federal Safe Drinking Water Act protects the quality of the nation's public drinking water through the adoption of drinking water standards and controlling the injection of waste fluids, including saltwater disposal fluids, into below-ground formations that may adversely affect drinking water sources.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas activities using hydraulic fracturing techniques, which could potentially cause a decrease in the completion of new oil and gas wells, an increase in compliance costs, and delays, all of which could adversely affect our financial position, results of operations and cash flows. As new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local levels, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements, which could result in additional permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and gas that we are ultimately able to produce from our reserves.

We believe it is reasonably likely that the trend in local and state environmental legislation and regulation will continue toward stricter standards, while the trend in federal environmental legislation and regulation faces an uncertain future under the Trump administration. While we believe we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot give any assurance that we will not be adversely affected in the future.

Environmental, Health and Safety Initiatives. We are committed to exceptional safety, health, and environmental stewardship; making a positive difference in the communities where we live and work; and transparency in reporting on our progress in these areas. We set annual goals for our environmental, health and safety program focused on reducing the number of safety related incidents and the number and impact of spills of produced fluids. In addition, we set annual goals for GHG emissions intensity and methane emissions as a percentage of total methane produced. We also periodically conduct audits of our operations to ensure regulatory compliance and we strive to provide appropriate training for our employees. Reducing air emissions as a result of leaks, venting, or flaring of gas during operations has become a major focus area for regulatory efforts and for our compliance efforts. While flaring is sometimes necessary, reducing these volumes is a priority for us. To avoid flaring when possible, we restrict testing periods and connect our production to gas pipeline infrastructure as quickly as possible after well completions. We have incurred in the past, and expect to incur in the future, capital costs related to environmental compliance. Such expenditures are included within our overall capital budget and are not separately itemized.

Available Information

Our internet website address is www.sm-energy.com. We routinely post important information for investors on our website. Within our website's investor relations section, we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC, and can be located at www.sec.gov. We also make available through our website our Corporate Governance Guidelines, Code of Business Conduct and Conflict of Interest Policy, Financial Code of Ethics, and the Charters of the Audit, Compensation, Executive, and Nominating and Corporate Governance Committees of our Board of Directors. Information on our website is not incorporated by reference into this report and should not be considered part of this document.

ITEM 1A. RISK FACTORS

In addition to the other information included in this report, the following risk factors should be carefully considered when evaluating an investment in us.

Risks Related to Our Business

Oil, gas, and NGL prices are volatile, and declines in prices adversely affect our profitability, financial condition, cash flows, access to capital, and ability to grow.

Our revenues, operating results, profitability, future rate of growth, and the carrying value of our oil and gas properties depend heavily on the prices we receive for oil, gas, and NGL sales. Oil, gas, and NGL prices also affect our cash flows available for capital expenditures and other items, our borrowing capacity, and the volume and value of our oil, gas, and NGL reserves. For example, the amount of our borrowing base under our Credit Agreement is subject to periodic redetermination based on oil, gas, and NGL prices specified by our bank group at the time of redetermination. In addition, we may have oil and gas property impairments or downward revisions of estimates of proved reserves if prices fall significantly. Please refer to *Significant Developments in 2019* and *Reserves* in Part I, Items 1 and 2 *Comparison of Financial Results and Trends Between 2019 and 2018 and Between 2018 and 2017* in Part II, Item 7, and *Note 1 – Summary of Significant Accounting Policies*, *Note 11 – Fair Value Measurements*, and *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 for specific discussion.

Historically, the markets for oil, gas, and NGLs have been volatile, and they are likely to continue to be volatile. Wide fluctuations in oil, gas, and NGL prices may result from relatively minor changes in the supply of and demand for oil, gas, and NGLs, market uncertainty, and other factors that are beyond our control, including:

- global and domestic supplies of oil, gas, and NGLs, and the productive capacity of the industry as a whole;
- the level of consumer demand for oil, gas, and NGLs;
- overall global and domestic economic conditions;
- weather conditions;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities in regional or localized areas;
- liquefied natural gas deliveries to and from the United States;
- the price and availability of alternative fuels;
- technological advances and regulations affecting energy consumption and conservation;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting countries to maintain effective oil price and production controls;
- political instability or armed conflict in oil or gas producing regions;
- actual or perceived epidemic risks, such as the Coronavirus outbreak in early 2020;
- strengthening and weakening of the United States dollar relative to other currencies;
- stockholder activism or activities by non-governmental organizations to limit sources of funding or restrict the exploration and production of oil, gas, and NGLs and related infrastructure; and
- governmental regulations and taxes.

Declines in oil, gas, and NGL prices would reduce our revenues and could also reduce the amount of oil, gas, and NGLs that we can produce economically, which could have a materially adverse effect on us.

Weakness in economic conditions or uncertainty in financial markets may have material adverse impacts on our business that we cannot predict.

In the last decade, the United States and global economies and financial systems have experienced turmoil and upheaval characterized by extreme volatility in prices of equity and debt securities, periods of diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse, or sale of financial institutions, and an unprecedented level of intervention by the United States federal government and other governments. Weakness or uncertainty in the United States economy or other large economies could materially adversely affect our business and financial condition. For example:

- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables;
- the liquidity available under our Credit Agreement could be reduced if any lender is unable to fund its commitment;
- our ability or the ability of our suppliers or contractors to access the capital markets may be restricted or non-existent at a time when we or they would like, or need, to raise capital for our or their business, including for the exploration and/or development of reserves;
- our commodity derivative contracts could become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection; and
- variable interest rate spread levels, including for LIBOR (or any applicable replacement rate) and the prime rate, could increase significantly, resulting in higher interest costs for unhedged variable interest rate based borrowings under our Credit Agreement.

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

Our future operations depend on our ability to find, develop, and acquire oil, gas, and NGL reserves that are economically producible. Our properties produce oil, gas, and NGLs at a declining rate over time. In order to maintain current production rates, we must locate, develop and acquire new oil, gas, and NGL reserves to replace those being depleted by production. Competition for oil and gas properties is intense, and many of our competitors have financial, technical, human, and other resources necessary to evaluate and integrate acquisitions that are substantially greater than those available to us.

For our prior acquisitions, as well as any future acquisitions we may complete, a successful outcome for our business will depend on a number of factors, many of which are beyond our control. These factors include the purchase price and transaction costs for the acquisition, future oil, gas, and NGL prices, the ability to reasonably estimate the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation, and development activities on the acquired properties, and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates, and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. Our customary review in connection with acquisitions will not necessarily reveal, or allow us to fully assess, all existing or potential problems and deficiencies with such properties. We do not inspect every well, and even when we inspect a well, we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. We often acquire interests in properties on an “as-is” basis with limited remedies for breaches of representations and warranties.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of unique risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

Substantial capital is required to develop and replace our reserves.

We must make substantial capital expenditures to find, acquire, develop, and produce oil, gas, and NGL reserves. Future cash flows and the availability of financing are subject to a number of factors, such as the level of production from existing wells, prices received for oil, gas, and NGL sales, our success in locating, developing and acquiring new reserves, and the orderly functioning of credit and capital markets. If our cash flows from operations are less than expected, we may reduce our planned capital expenditures unless we can raise additional funds through debt or equity financing or the divestment of assets. Debt or equity financing may not always be available to us in sufficient amounts or on acceptable terms, and the proceeds offered to us for potential divestitures may not always be acceptable to us. Any downgrades to our credit ratings may make it more difficult or expensive for us to borrow additional funds.

If our revenues decrease in the future due to lower oil, gas, or NGL prices, decreased production, or other reasons, and if we cannot access sufficient liquidity under our Credit Agreement, other acceptable debt or equity financing arrangements, or through the sale of assets, our ability to execute development plans, replace our reserves, maintain our acreage, or maintain production levels could be greatly limited.

Our ability to sell oil, gas, and NGLs, and/or receive market prices for our production, may be adversely affected by constraints on gathering systems, processing facilities, pipelines, and other transportation systems owned or operated by third-parties or by other interruptions beyond our control, which could obstruct, limit, or eliminate our access to oil, gas, and NGL markets.

The marketability of our oil, gas, and NGL production depends in part on the availability, proximity, and capacity of gathering systems, processing facilities, pipelines, and other transportation systems, which are generally owned or operated by third-parties. Any significant interruption in service from, damage to, or lack of available capacity in these systems and facilities can result in the shutting-in of producing wells, the delay, or discontinuance of development plans for our properties, or lower price realizations. Although we have some influence over the processing and transportation of our operated production, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil, gas, and NGL production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines or processing facilities, infrastructure or capacity constraints, and general economic conditions could adversely affect our ability to produce, gather, process, transport, or market oil, gas, and NGLs.

In particular, if production from the Midland Basin continues to grow, the amount of oil, gas, and NGLs being produced by us and others could exceed the capacity of, and result in constraints on, available gathering and transportation systems, pipelines, processing facilities, and other infrastructure. In such circumstances, it will be necessary for pipelines, gathering and transportation systems, processing facilities, and additional infrastructure to be expanded, built, or developed to accommodate anticipated production. Certain processing, pipeline, and other gathering, transportation, and infrastructure projects that might be, or are being, considered for these areas may not be developed timely or at all due to lack of financing or other constraints, including regulatory constraints. Capital and other constraints could also limit our ability to build or access intrastate gathering and transportation systems necessary to transport our production to interstate pipelines or other points of sale or delivery. In such event, we might have to delay or discontinue development activities or shut in our wells to wait for sufficient infrastructure development or capacity expansion and/or sell production at significantly lower prices, which would adversely affect our results of operations and cash flows. In addition, the operations of the third-parties on whom we rely for gathering, processing, and transportation services are subject to complex and stringent laws and regulations, which require obtaining and maintaining numerous permits, approvals, and certifications from various federal, state, and local government authorities. These third-parties may incur substantial costs in order to comply with existing and future laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the availability and costs of such services. Similarly, a failure to comply with such laws and regulations by the third-parties on whom we rely could have a material adverse effect on our business, financial condition, and results of operations.

A portion of our production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline, gathering, processing or transportation system access or capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market or other conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flows and results of operations.

Downgrades in our credit ratings by various credit rating agencies could impact our access to capital and materially adversely affect our business and financial condition.

Our debt rating levels could have materially adverse consequences on our business and future prospects and could:

- limit our ability to access debt markets, including for the purpose of refinancing our existing debt;
- cause us to refinance or issue debt with less favorable terms and conditions, which debt may restrict, among other things, our ability to make any dividend distributions or repurchase shares;
- negatively impact current and prospective customers' willingness to transact business with us;
- impose additional insurance, guarantee and collateral requirements;
- limit our access to bank and third-party guarantees, surety bonds and letters of credit; and

- cause our suppliers and financial institutions to lower or eliminate the level of credit provided through payment terms or intraday funding when dealing with us, thereby increasing the need for higher levels of cash on hand, which would decrease our ability to repay outstanding indebtedness.

We cannot provide assurance that any of our current Debt Ratings will remain in effect for any given period of time or that a Debt Rating will not be further lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances warrant.

Competition in our industry is intense, and many of our competitors have greater financial, technical, and human resources than we do.

We face intense competition from major oil and gas companies, independent oil and gas exploration and production companies, and institutional and individual investors who seek oil and gas investments throughout the world, as well as the equipment, expertise, labor, and materials required to operate oil and gas properties. Many of our competitors have financial, technical, and other resources exceeding those available to us, and many oil and gas properties are sold in a competitive bidding process in which our competitors may be able and willing to pay more for exploratory and development prospects and productive properties, or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for properties. We may not be successful in acquiring and developing profitable properties in the face of this competition. In addition, other companies may have a greater ability to continue drilling activities during periods of low oil or gas prices and to absorb the burden of current and future governmental regulations and taxation. In addition, shortages of equipment, labor, or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. Our inability to compete effectively with companies in any area of our business could have a material adverse impact on our business activities, financial condition, and results of operations.

The loss of key personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of their services could adversely affect our business. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen, and other professionals. Competition for many of these professionals can be intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

The actual quantities and present value of our proved oil, gas, and NGL reserves may be less than we have estimated.

This report and certain of our other SEC filings contain estimates of our proved oil, gas, and NGL reserves and the estimated future net revenues from those reserves. These estimates are based on various assumptions, including assumptions required by the SEC relating to oil, gas, and NGL prices, drilling and completion costs, gathering and transportation costs, operating expenses, capital expenditures, effects of governmental regulation, taxes, timing of operations, and availability of funds. The process of estimating oil, gas, and NGL reserves is complex and involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir. These estimates depend on many variables, and changes often occur as our knowledge of these variables evolves. Therefore, these estimates are inherently imprecise. In addition, our reserve estimates for properties that do not have a significant production history may be less reliable than estimates for properties with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates, and the timing and/or amount of development expenditures.

Actual future production; prices for oil, gas, and NGLs; revenues; production taxes; development expenditures; operating expenses; and quantities of producible oil, gas, and NGL reserves will most likely vary from those estimated. Any significant variance of any nature could materially affect the estimated quantities of and present value related to proved reserves disclosed by us, and the actual quantities and present value may be significantly less than what we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of operations, results of exploration and development activity, prevailing oil, gas, and NGL prices, costs to develop and operate properties, and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production on adjacent properties, which we may not control.

As of December 31, 2019, 47 percent, or 214.9 MMBOE, of our estimated proved reserves were proved undeveloped. In order to develop our proved undeveloped reserves, as of December 31, 2019, we estimate approximately $2.0 billion of capital expenditures would be required. Although we have estimated our proved reserves and the costs associated with these proved reserves in accordance with industry standards, estimated costs may not be accurate, development may not occur as scheduled, and actual results may not occur as estimated.

You should not assume that the standardized measure of discounted future net cash flows or PV-10 included in this report represent the current market value of our estimated proved oil, gas, and NGL reserves. Management has based the estimated discounted future net cash flows from proved reserves on price and cost assumptions required by the SEC, whereas actual future prices and costs may be materially higher or lower. For example, the present value of our proved reserves as of December 31, 2019, was estimated using 12-month average sales prices of $55.69 per Bbl of oil (NYMEX WTI spot price), $2.58 per MMBtu of gas (NYMEX Henry Hub spot price), and $22.68 per Bbl of NGL (OPIS spot price). We then adjust these prices to reflect appropriate quality and location differentials over the period in estimating our proved reserves. During 2019, our monthly average realized oil prices before the effect of derivative settlements were as high as $61.66 per Bbl and as low as $42.28 per Bbl for oil, were as high as $3.33 per Mcf and as low as $2.05 per Mcf for gas, and were as high as $20.06 per Bbl and as low as $13.84 per Bbl for NGLs. Many other factors will affect actual future net cash flows, including:

- amount and timing of actual production;
- supply and demand for oil, gas, and NGLs;
- curtailments or increases in consumption by oil purchasers and gas pipelines;
- changes in government regulations or taxes, including severance and excise taxes; and
- escalations or reductions in service provider and equipment costs resulting from changes in supply and demand.

The timing of production from oil and gas properties and of related expenses affects the timing of actual future net cash flows from proved reserves, and thus their actual present value. Our actual future net cash flows could be less than the estimated future net cash flows for purposes of computing PV-10. In addition, the 10 percent discount factor required by the SEC to be used to calculate PV-10 for reporting purposes is not necessarily the most appropriate discount factor given actual interest rates, costs of capital, and other risks to which our business and the oil and gas industry in general are subject.

Our disposition activities may be subject to factors beyond our control, and in certain cases we may retain unforeseen liabilities for certain matters.

We regularly sell non-core assets in order to increase capital resources available for core assets and other purposes and to create organizational and operational efficiencies. We also occasionally sell interests in core assets for the purpose of accelerating the development and increasing efficiencies in other core assets. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third-parties, the availability of purchasers willing to acquire the assets on terms we deem acceptable, or other matters or uncertainties that could impact such dispositions, including whether transactions could be consummated or completed in the form or timing and for the value that we anticipate. We at times may be required to retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liabilities or of the indemnification obligations may be difficult to quantify at the time of the transaction and ultimately could be material.

We have limited control over the activities on properties we do not operate.

Some of our properties are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including the nature and timing of drilling and operational activities, the operator’s skill and expertise, compliance with environmental, safety and other regulations, the approval of other participants in such properties, the selection and application of suitable technology, or the amount of expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the expenditures of such properties. These limitations and our dependence on the operator and other working interest owners in these projects could cause us to incur unexpected future costs and materially and adversely affect our financial condition and results of operations.

We rely on third-party service providers to conduct drilling and completion and other related operations on properties we operate.

Where we are the operator of a property, we rely on third-party service providers to perform necessary drilling and completion and other related operations. The ability of third-party service providers to perform such operations will depend on those service providers’ ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, gas, and NGLs, prevailing economic conditions and financial, business, and other factors. In addition, sustained low commodity prices could cause third-party service providers to consolidate or declare bankruptcy, which could limit our options for engaging such providers. The failure of a third-party service provider to adequately perform operations could delay drilling or completion or reduce production from the property and adversely affect our financial condition and results of operations.

Title to the properties in which we have an interest may be impaired by title defects.

We generally rely on title reports in acquiring oil and gas leasehold interests. We obtain title opinions prior to commencing initial drilling operations on the properties we operate. Undeveloped acreage has greater risk of title defects than developed acreage and title insurance is not generally available for oil and gas properties. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and title abstract facilities before acquiring a specific mineral interest and/or undertaking drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title. Generally, under the terms of the operating agreements affecting our properties, any monetary loss attributable to a loss of title is to be borne by all parties to any such agreement in proportion to their interests in such property. A material title defect can reduce the value of a property or render it worthless, thus adversely affecting our financial condition, results of operations, and operating cash flow if such property is of sufficient value.

Exploration and development drilling may not result in commercially producible reserves.

Oil and gas drilling, completion, and production activities are subject to numerous risks, including the risk that no commercially producible oil, gas, or NGLs will be found. The cost of drilling and completing wells is often uncertain, and oil, gas, or NGLs drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors may include, but are not limited to:

- unexpected adverse drilling or completion conditions;
- title problems;
- disputes with owners or holders of surface interests on or near areas where we operate;
- pressure or geologic irregularities in formations;
- engineering and construction delays;
- equipment failures or accidents;
- hurricanes, tornadoes, flooding, or other adverse weather conditions;
- governmental permitting delays;
- compliance with environmental and other governmental requirements; and
- shortages or delays in the availability of or increases in the cost of drilling rigs and crews, fracture stimulation crews and equipment, pipe, chemicals, water, sand, and other supplies.

The prevailing prices for oil, gas, and NGLs affect the cost of and the demand for drilling rigs, completion and production equipment, and other related services. However, changes in costs may not occur simultaneously with corresponding changes in commodity prices. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the available rigs in that region.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays that jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a materially adverse effect on our ability to explore or develop our properties.

The wells we drill may not be productive, and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well if oil, gas, or NGLs are present, or whether they can be produced economically. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover drilling and completion costs. Even if sufficient amounts of oil, gas, or NGLs exist, we may damage a potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing a well, which could result in reduced or no production from the well, significant expenditure to repair the well, and/or the loss and abandonment of the well.

Results in newer resource plays may be more uncertain than results in resource plays that are more developed and have longer established production histories. We and the industry generally have less information with respect to the ultimate recoverability of reserves and the production decline rates in newer resource plays than other areas with longer histories of development and production. Drilling and completion techniques that have proven to be successful in other resource plays are being used in the early development of new plays; however, we can provide no assurance of the ultimate success of these drilling and completion techniques.

In addition, a significant part of our strategy involves increasing our inventory of drilling locations. Such multi-year drilling inventories can be more susceptible to long-term uncertainties that could materially alter the occurrence or timing of actual drilling. Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled, although we have the present intent to do so for locations booked as proved undeveloped locations, or if we will be able to produce oil, gas, or NGLs from these potential drilling locations.

We may not be able to obtain any options or lease rights in potential drilling locations that we identify. Unless production is established within the spacing units covering undeveloped acres on which our drilling locations are identified, the leases for such acreage will expire and we will lose our right to develop the related properties. Our total net acreage as of February 6, 2020, that is scheduled to expire over the next three years, represents approximately one percent of our total net undeveloped acreage as of December 31, 2019. Although we have identified numerous potential drilling locations, we may not be able to economically drill for and produce oil, gas, or NGLs from all of them, and our actual drilling activities may materially differ from those presently identified, which could adversely affect our financial condition, results of operations and operating cash flow.

Part of our strategy involves drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques. The results of our planned exploratory and delineation drilling in these plays are subject to drilling and completion technique risks, and results may not meet our expectations for reserves or production. As a result, we may incur material write-downs, and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Many of our operations involve utilizing the latest drilling and completion techniques as developed by us, other operators and our service providers in order to maximize production and ultimate recoveries and therefore generate the highest possible returns. Risks we face while drilling include, but are not limited to, landing our well bore outside the desired drilling zone, deviating from the desired drilling zone while drilling horizontally through the formation, the inability to run our casing the entire length of the well bore, and the inability to run tools and recover equipment consistently through the horizontal well bore. Risks we face while completing our wells include, but are not limited to, the inability to fracture stimulate the planned number of stages, the inability to run tools and other equipment the entire length of the well bore during completion operations, the inability to recover such tools and other equipment, and the inability to successfully clean out the well bore after completion of the final fracture stimulation.

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, limited access to gathering systems and takeaway capacity, and/or prices for oil, gas, and NGLs decline, then the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of oil and gas properties and the value of our undeveloped acreage could decline in the future.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing, or operating wells that they own.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, result in increased lease operating expenses and adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Our commodity derivative contract activities may result in financial losses or may limit the prices we receive for oil, gas, and NGL sales.

To mitigate a portion of the exposure to potentially adverse market changes in oil, gas, and NGL prices and the associated impact on cash flows, we have entered into various derivative contracts. Our derivative contracts in place include swap and collar arrangements for oil, and swap arrangements for gas and NGLs. We have also entered into basis swap arrangements for a portion of our expected Midland Basin oil production to reduce volatility associated with location differentials between where these volumes are sold and NYMEX WTI. As of December 31, 2019, we were in a net accrued asset position of $21.5 million with respect to our oil, gas, and NGL derivative activities. These activities may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- one or more counterparties to our commodity derivative contracts default on their contractual obligations; or
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the commodity derivative contract arrangement.

In addition, commodity derivative contracts may limit the prices we receive for our oil, gas, and NGL sales if oil, gas, or NGL prices rise substantially over the price established by the commodity derivative contract.

The inability of customers or co-owners of assets to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from oil, gas, and NGL sales or joint interest billings to co-owners of oil and gas properties we operate. This concentration of customers and joint interest owners may impact our overall credit risk because these entities may be similarly affected by various economic and other market conditions, including declines in oil, gas, and NGL prices. The loss of one or more of these customers could reduce competition for our products and negatively impact the prices of commodities we sell. We do not believe the loss of any single purchaser would materially impact our operating results, as we have numerous options for purchasers in each of our operating areas for our oil, gas, and NGL production. Please refer to *Concentration of Credit Risk and Major Customers* in *Note 1 – Summary of Significant Accounting Policies,* in Part II, Item 8 of this report for further discussion of our concentration of credit risk and major customers. Additionally, the inability of our co-owners to pay joint interest billings could negatively impact our cash flows and financial ability to drill and complete current and future wells.

We have entered into firm transportation contracts that require us to pay fixed sums of money to our counterparties regardless of quantities actually shipped, processed, or gathered. If we are unable to deliver the necessary quantities of oil, gas, NGL, or produced water to our counterparties, our results of operations, financial position, and liquidity could be adversely affected.

As of December 31, 2019, we were contractually committed to deliver 24 MMBbl of oil and 424 Bcf of gas through 2023, and 18 MMBbl of produced water through 2027. We may enter into additional firm transportation agreements as we expand the development of our resource plays. At the current time, we do not have enough proved developed reserves to offset these contractual liabilities, but we expect to develop reserves that will meet or exceed the commitments and therefore do not expect any material shortfalls. In the event we encounter delays in drilling and completing our wells or otherwise due to construction, interruptions of operations, or delays in connecting new volumes to gathering systems or pipelines for an extended period of time, or if we further limit our capital expenditures due to future commodity price declines or for other reasons, the requirements to pay for quantities not delivered could have a material impact on our results of operations, financial position, and liquidity.

Future oil, gas, and NGL price declines or unsuccessful exploration efforts may result in write-downs of our asset carrying values.

We follow the successful efforts method of accounting for our oil and gas properties. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If commercial quantities of hydrocarbons are not discovered with an exploratory well, the costs of drilling the well are expensed.

The capitalized costs of our oil and gas properties, on a depletion pool basis, cannot exceed the estimated undiscounted future net cash flows of that depletion pool. If net capitalized costs exceed undiscounted future net cash flows, we generally must write down the costs of each depletion pool to the estimated discounted future net cash flows of that depletion pool. Write downs for unproved properties are also evaluated for carrying costs in excess of fair value. This evaluation considers the potential for abandonment due to lease expirations, losses on acreage due to title defects, changes in development plans, and other inherent acreage risks. For the years ended December 31, 2019, 2018, and 2017, we incurred impairment of oil and gas properties expense totaling $33.8 million, $49.9 million, and $16.1 million, respectively. If the prices of oil, gas, or NGLs decline, or we have unsuccessful exploration efforts, it could cause additional proved and/or unproved property impairments in the future.

We review the carrying values of our properties for indicators of impairment on a quarterly basis using the prices in effect as of the end of each quarter. Once incurred, a write-down of oil and gas properties held for use cannot be reversed at a later date, even if oil, gas, or NGL prices increase.

Lower oil, gas, or NGL prices could limit our ability to borrow under our Credit Agreement.

Our Credit Agreement has a current commitment amount of $1.2 billion, subject to a borrowing base that the lenders redetermine semi-annually based on the bank group’s assessment of the value of our proved reserves, which in turn is impacted by oil, gas, and NGL prices. The borrowing base under our Credit Agreement is $1.6 billion, up from $1.5 billion at December 31, 2018. The next semi-annual redetermination date is scheduled for April 1, 2020. Divestitures of additional properties, incurrence of additional debt, or declines in commodity prices could limit our borrowing base and reduce the amount we can borrow under our Credit Agreement.

The amount of our debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt.

As of December 31, 2019, we had the following outstanding long-term debt:

- $476.8 million of long-term senior unsecured debt relating to our 6.125% Senior Notes due 2022 (“2022 Senior Notes”) that we issued on November 17, 2014;
- $500.0 million of long-term senior unsecured debt relating to our 5.0% Senior Notes due 2024 (“2024 Senior Notes”) that we issued on May 20, 2013;
- $500.0 million of long-term senior unsecured debt relating to our 5.625% Senior Notes due 2025 (“2025 Senior Notes”) that we issued on May 21, 2015;
- $500.0 million of long-term senior unsecured debt relating to our 6.75% Senior Notes due 2026 (“2026 Senior Notes”) that we issued on September 12, 2016;
- $500.0 million of long-term senior unsecured debt relating to our 6.625% Senior Notes due 2027 (“2027 Senior Notes”, and all senior notes collectively referred to as the “Senior Notes”) that we issued on August 20, 2018; and,
- $172.5 million in aggregate principal amount of long-term senior unsecured convertible debt relating to our 1.50% Senior Convertible Notes due July 1, 2021 (“Senior Convertible Notes”) that we issued on August 12, 2016.

Additionally, we had $122.5 million of outstanding borrowings under our Credit Agreement as of December 31, 2019, resulting in $1.1 billion of available borrowing capacity under our secured credit facility. Our long-term debt represented 50 percent of our total book capitalization as of December 31, 2019.

Our indebtedness could have important consequences for our operations, including:

- making it more difficult for us to obtain additional financing in the future for our operations and potential acquisitions, working capital requirements, capital expenditures, debt service, or other general corporate requirements;

- requiring us to dedicate a substantial portion of our cash flows from operations to the repayment of our debt and the service of interest costs associated with our debt, rather than to productive investments;

- limiting our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making acquisitions, and paying dividends;

- placing us at a competitive disadvantage compared to our competitors with less debt; and

- making us more vulnerable in the event of adverse economic or industry conditions or a downturn in our business.

If our business does not generate sufficient cash flow from operations or future sufficient borrowings are not available to us under our Credit Agreement or from other sources, we might not be able to service our debt, issue additional debt, or fund our planned capital expenditures and other liquidity needs. If we are unable to service our debt, due to inadequate liquidity or otherwise, we may have to delay or cancel acquisitions, defer capital expenditures, sell equity securities, divest assets, and/or restructure or refinance our debt. We might not be able to sell our equity, sell our assets, or restructure or refinance our debt on a timely basis or on satisfactory terms or at all. In addition, the terms of our existing or future debt agreements, including our Credit Agreement and any future credit agreements, may prohibit us from pursuing any of these alternatives. Further, changes in the credit ratings of our debt may negatively affect the cost, terms, conditions, and availability of future financing.

Our debt agreements, including our Credit Agreement and the indentures governing our Senior Notes and our Senior Convertible Notes, permit us to incur additional debt in the future, subject to compliance with restrictive covenants under those agreements. In addition, entities we may acquire in the future could have significant amounts of debt outstanding that we could be required to assume, and in some cases accelerate repayment thereof, in connection with the acquisition, or we may incur our own significant indebtedness to consummate an acquisition.

As discussed above, our Credit Agreement is subject to periodic borrowing base redeterminations. We could be forced to repay a portion of our bank borrowings in the event of a downward redetermination of our borrowing base, and we may not have sufficient funds to make such repayment at that time. If we do not have sufficient funds and are otherwise unable to negotiate adjustments to our borrowing base or arrange new financing, we may be forced to sell significant assets.

The agreements governing our debt arrangements contain various covenants that limit our discretion in the operation of our business, could prohibit us from engaging in transactions we believe to be beneficial, and could lead to the accelerated repayment of our debt.

Our debt agreements, including our Credit Agreement and the indentures governing our Senior Notes and our Senior Convertible Notes, contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under our Credit Agreement is subject to compliance with certain financial covenants. Financial covenants under the Credit Agreement require that our (a) total funded debt, as defined in the Credit Agreement, to adjusted EBITDAX ratio for the most recently ended four consecutive fiscal quarters (excluding the first three quarters which will use annualized adjusted EBITDAX), cannot be greater than 4.25 to 1.00 beginning with the quarter ending December 31, 2018, through and including the fiscal quarter ending December 31, 2019, and for each quarter ending thereafter, the ratio cannot be greater than 4.00 to 1.00; and (b) adjusted current ratio cannot be less than 1.0 to 1.0 as of the last day of any fiscal quarter. Our Credit Agreement also requires us to comply with certain additional financial covenants, including a requirement that we limit our annual cash dividends to no more than $50.0 million. These restrictions on our ability to operate our business could seriously harm our business by, among other things, limiting our ability to take advantage of financings, mergers and acquisitions, and other corporate opportunities. We were in compliance with all financial and non-financial covenants as of December 31, 2019, and through the filing of this report. Please refer to *Non-GAAP Financial Measures* in Part II, Item 7 of this report for our definition of adjusted EBITDAX.

The respective indentures governing the Senior Notes and Senior Convertible Notes also contain covenants that, among other things, limit our ability and the ability of our subsidiaries to:

- incur additional debt;

- make certain dividends or pay dividends or distributions on our capital stock or purchase, redeem, or retire common stock;

- sell assets, including common stock of our subsidiaries;

- restrict dividends or other payments of our subsidiaries;

- create liens that secure debt;
- enter into transactions with affiliates; and
- merge or consolidate with, or transfer or lease all or substantially all of our assets to another company.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all or a portion of our indebtedness. We do not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

Our increasing dependence on digital technologies puts us at risk for a cyber incident that could result in information theft, data corruption, operational disruptions or financial loss.

We are subject to cybersecurity risks. The oil and gas industry is increasingly dependent on digital technology in all aspects of our business. We use digital technology to conduct certain of our drilling development, production and gathering activities, manage drilling rigs and completion equipment, gather and interpret seismic data, conduct reservoir modeling, record financial and operating data, and maintain employee and other databases. Our service providers, including those who gather, process and market our oil, gas and NGLs, are also increasingly reliant on digital technology. Our and their reliance on this technology increasingly puts us at risk for technology system failures, data or network disruptions, cyberattacks and other breaches in cybersecurity. Power failures, telecommunication or other system failures due to hardware or software malfunctions, computer viruses, vandalism, terrorism, natural disasters, fire, flood, human error or other means could significantly impair our ability to conduct our business.

Cybersecurity attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. Deliberate attacks on, or security breaches in our systems, infrastructure, the systems and infrastructure of third-parties, or cloud-based applications could lead to disclosure of confidential information, a corruption or loss of our proprietary data, delays in production or exploration activities, difficulty in completing or settling transactions, challenges in maintaining our books and records, environmental damage, communication or other operational disruptions, and liability to third parties. Any insurance we might obtain in the future may not provide adequate protection from these risks. Any such events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability. As these cyber risks continue to evolve and our dependence on digital technologies grows, we may be required to expend significant additional resources to continue to modify or enhance our protective measures and remediate cyber vulnerabilities.

Our business could be negatively impacted by security threats, including cybersecurity threats, terrorism, armed conflict, and other disruptions.

As an oil, gas, and NGL producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel, or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

The threat of terrorism and the impact of military and other actions have caused instability in world financial markets and could lead to increased volatility in prices for oil, gas, and NGLs, all of which could adversely affect the markets for our production. Energy assets might be specific targets of terrorist attacks. While we currently maintain some insurance that provides coverage against terrorist attacks, such insurance has become increasingly expensive and difficult to obtain. As a result, insurance providers may not continue to offer this coverage to us on terms we consider reasonable, or at all. In addition, this insurance may not cover all of our losses for a terrorist attack. These developments have subjected our operations to increased risk and, depending on their occurrence and ultimate magnitude, could have a material adverse effect on our business, financial condition, or results of operations.

Negative public perception and investor sentiment regarding our business and the oil and gas industry as a whole could adversely affect our business, operations and our ability to attract capital.

Certain segments of the public as a whole, and the investment community in particular, have developed negative sentiment towards our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment management firms, sovereign wealth and pension funds, university endowments and other investment advisors, have adopted policies to discontinue or reduce their investments in the oil and gas sector based on social and environmental considerations. Furthermore, other influential stakeholders have pressured commercial and investment banks to reduce or cease financing of oil and gas companies and related infrastructure projects.

Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

We are subject to operating and environmental risks and hazards that could result in substantial losses or liabilities that may not be fully insured.

Oil and gas operations are subject to many risks, including human error and accidents, that could cause personal injury, death, property damage, well blowouts, craterings, explosions, uncontrollable flows of oil, gas and NGLs, or well fluids, releases or spills of completion fluids, spills or releases from facilities and equipment used to deliver or store these materials, spills or releases of brine or other produced or flowback water, subsurface conditions that prevent us from stimulating the planned number of completion stages, accessing the entirety of the wellbore with our tools during completion, or removing materials from the wellbore to allow production to begin, fires, adverse weather such as hurricanes or tornadoes, freezing conditions, floods, droughts, formations with abnormal pressures, pipeline ruptures or spills, pollution, seismic events, releases of toxic gas such as hydrogen sulfide, and other environmental risks and hazards. If any of these types of events occurs, we could sustain substantial losses.

Furthermore, if we experience any of the problems with well stimulation and completion activities referenced above, our ability to explore for and produce oil, gas, or NGLs may be adversely affected. We could incur substantial losses or otherwise fail to realize reserves in particular formations as a result of the need to shut down, abandon, or relocate drilling operations, the need to modify drill sites to lessen the risk of spills or releases, the need to investigate and/or remediate any spills, releases or ground water contamination that might have occurred, and the need to suspend our operations.

There is inherent risk of incurring significant environmental costs and liabilities in our operations due to our current and past generation, handling, and disposal of materials, including produced water, solid and hazardous wastes, and petroleum hydrocarbons. We may incur joint and several, and/or strict liability under applicable United States federal and state environmental laws in connection with releases of petroleum hydrocarbons and other hazardous substances at, on, under or from our leased or owned properties, some of which have been used for oil and gas exploration and production activities for a number of years, often by third-parties not under our control. For our outside-operated properties, we are dependent on the operator for operational and regulatory compliance and could be subject to liabilities in the event of non-compliance. These properties and the wastes disposed thereon or therefrom could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including CERCLA or the Superfund law, RCRA, the Clean Water Act, the CAA, the OPA, and analogous state laws. Under various implementing regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury or property damage, including induced seismicity damage, allegedly caused by the release of petroleum hydrocarbons or other hazardous substances into the environment. As a result, we may incur substantial liabilities to third-parties or governmental entities, which could reduce or eliminate funds available for exploration, development, or acquisitions, or cause us to incur losses.

We maintain insurance against some, but not all, of these potential risks and losses. We have significant but limited coverage for sudden environmental damage. We do not believe that insurance coverage for the full potential liability that could be caused by environmental damage that occurs gradually over time is appropriate for us at this time given the nature of our operations and the nature and cost of such coverage. Further, we may elect not to obtain insurance coverage under circumstances where we believe that the cost of available insurance is excessive relative to the risks to which we are subject. Accordingly, we may be subject to liability or may lose substantial assets in the event of environmental or other damages. If a significant accident or other event occurs and is not fully covered by insurance, we could suffer a material loss.

Our operations are subject to complex laws and regulations, including environmental regulations that result in substantial costs and other risks.

Federal, state, and local authorities extensively regulate the oil and gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may become more stringent and, as a result, may affect, among other things, the pricing, or marketing of oil, gas, and NGL production. Non-compliance with statutes and regulations and more vigorous enforcement of such statutes and regulations by regulatory agencies may lead to substantial administrative, civil, and criminal penalties, including the assessment of natural resource damages, the imposition of significant investigatory and remedial obligations and may also result in the suspension or termination of our operations. The overall regulatory burden on the industry increases the cost to place, design, drill, complete, install, operate, and abandon wells and related facilities and, in turn, decreases profitability.

Governmental authorities regulate various aspects of drilling for and the production of oil, gas, and NGLs, including the permit and bonding requirements of drilling wells, the spacing of wells, the unitization or pooling of interests in oil and gas properties, rights-of-way and easements, disposal of produced water, environmental matters, occupational health and safety, the sharing of markets, production limitations, plugging, abandonment, restoration standards, and oil and gas operations. Public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain projects. Under certain circumstances, regulatory authorities may deny a proposed permit or right-of-way grant or impose conditions of approval to mitigate potential environmental impacts, which could, in either case, negatively affect our ability to explore or develop certain properties. Federal authorities also may require any of our ongoing or planned operations on federal leases to be delayed, suspended, or terminated. Any such delay, suspension, or termination could have a materially adverse effect on our operations.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state, and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, including the designation of previously unprotected wildlife or plant species as threatened or endangered in areas we operate in, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. Under existing or future environmental laws and regulations, we could incur significant liability, including joint and several, strict liability under federal, state, and local environmental laws for emissions and for discharges of oil, gas, and NGLs or other pollutants into the air, soil, surface water, or groundwater. We could be required to spend substantial amounts on investigations, litigation, and remediation for these emissions and discharges and other compliance issues. Any unpermitted release of petroleum or other pollutants from our operations could result not only in cleanup costs, but also natural resources, real or personal property and other damages and civil and criminal liabilities. The listing of additional wildlife or plant species as federally endangered or threatened could result in limitations on exploration and production activities in certain locations. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a materially adverse effect on us.

The impact of extreme weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Our operations on our Midland Basin and South Texas assets are adversely affected by the impact of extreme weather conditions and lease stipulations designed to protect various wildlife or plant species. In certain areas, drilling and other oil and gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs and completion equipment, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Wildlife seasonal restrictions may limit access to federal leases or across federal lands. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing, air quality, and greenhouse gas emissions could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is a common practice in the oil and gas industry used to stimulate the production of oil, gas, and NGLs from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques to many of our oil and gas properties, including our unconventional resource plays within our Midland Basin and South Texas assets. Hydraulic fracturing involves injecting water, sand, and certain chemicals under pressure to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and gas commissions. However, the EPA and other federal agencies have asserted federal regulatory authority over certain aspects of hydraulic fracturing activities, as outlined below.

The EPA has authority to regulate underground injections that contain diesel in the fluid system under the Safe Drinking Water Act. The EPA has published an interpretive memorandum and permitting guidance related to regulation of fracturing fluids using this regulatory authority. In June 2016, the EPA issued regulations under the Federal Clean Water Act establishing federal pre-treatment standards for wastewater generated by unconventional oil and gas operations during the hydraulic fracturing process. Under a recent settlement, the EPA had until March 2019 to decide whether to initiate rulemaking governing the disposal of wastewater from oil and gas development under RCRA Subtitle D. In April 2019, the EPA released its review, concluding that no new regulations were needed for managing wastewater based on the EPA’s conclusion that existing state regulations and best management practices are sufficiently protective of human health and the environment. If the EPA implements further regulations of hydraulic fracturing, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

Certain states, including Texas, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict, or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. Recently, municipalities have passed or proposed zoning ordinances that ban or strictly regulate hydraulic fracturing within city boundaries, setting the stage for challenges by state regulators and third-parties. Similar events and processes are playing out in several cities, counties, and townships across the United States. In the event that state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct, operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

In the recent past, several federal governmental agencies were actively involved in studies or reviews that focus on environmental aspects and impacts of hydraulic fracturing practices. For example, in December 2016, the EPA issued a final assessment of potential impacts to drinking water resources from hydraulic fracturing. On March 28, 2017, President Trump issued Executive Order 13783 entitled “Promoting Energy Independence and Economic Growth” (“Executive Order 13783”). Executive Order 13783 directed executive departments and agencies to review regulations that potentially burden the development or use of domestically produced energy resources and, as appropriate, suspend, revise, or rescind those that unduly burden domestic energy resources development.

We will continue to be subject to uncertainty associated with new regulatory suspensions, revisions or rescissions and inconsistent state and federal regulatory mandates that could adversely affect our production.

Further, as to air quality and GHG regulation of oil and gas sources, the overall trend has been toward increased regulation and requirements for reduced emissions. The Trump administration has taken steps toward rescinding or reviewing many of those regulations, but any deregulation will likely face immediate judicial challenges. The Obama administration took several actions to regulate air quality and GHGs, many of which remain in effect. For example, on August 16, 2012, the EPA issued final rules subjecting all new and modified oil and gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards ("NSPS") and all existing and new operations to the National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. The EPA rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards require the use of reduced emission completion ("REC") techniques developed in the EPA's Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line beginning in January 2015. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAP include maximum achievable control technology ("MACT") standards for those glycol dehydrators and certain storage vessels at major sources of hazardous air pollutants not previously subject to MACT standards. These rules require additional control equipment, changes to procedure, and extensive monitoring and reporting. In September 2013 and December 2014, the EPA published technical fixes to the 2012 NSPS, including standards for storage tanks subject to the NSPS. The amendments clarified stages for flowback and the point at which green completion equipment is required and updated requirements for storage tanks and leak detection requirements for processing plants. As part of the EPA's strategy during the Obama administration to reduce methane and ozone-forming volatile organic compound ("VOC") emissions from the oil and gas industry, on May 12, 2016, the EPA issued final regulations that amend and expand the 2012 regulations. The 2016 NSPS requires reduction of GHGs in the form of methane and VOCs from certain activities in oil and gas production, processing, transmission and storage and applies to facilities constructed, modified, or reconstructed after September 18, 2015. The final regulation requires, among other things, GHG and VOC standards for certain equipment, such as centrifugal compressors and reciprocating compressors; semi-annual leak detection and repair for well sites and quarterly for boosting and garnering compressor stations and natural gas transmission compressor stations; control requirements and emission limits for pneumatic pumps; and additional requirements for control of GHGs and VOCs from well completions. Both the 2012 and 2016 rules are the subjects of Petitions for Review before the U.S. Circuit Court of Appeals for the District of Columbia, though the litigation of both rules has been stayed. In June 2017, the EPA proposed a 2-year stay of the compliance requirements in the 2016 NSPS. In a related action in March 2017, the EPA withdrew the final information request it had issued in 2016 as part of an effort to develop standards under the CAA NSPS provisions for methane and other emissions from existing sources in the oil and natural gas industry. In September 2018, the EPA proposed changes to the 2016 NSPS amending specific provisions related to, among other things, fugitive emissions requirements. On August 29, 2019, the EPA proposed amendments to the 2012 and 2016 NSPS that would remove transmission and storage infrastructure from regulation of methane emissions and other VOCs. The amendments would also rescind methane requirements for oil and gas production and processing equipment. As an alternative, the EPA proposed to rescind the methane requirements for oil and gas altogether and sought comment on alternative interpretations of its authority to regulate pollutants under Section 111 of the Clean Air Act.

In October 2015, the EPA revised and lowered the ambient air quality standard for ozone in the U.S. under the CAA, from 75 parts per billion to 70 parts per billion, which is likely to result in more, and expanded, ozone non-attainment areas, which in turn will require states to adopt implementation plans to reduce emissions of ozone-forming pollutants, like VOCs and nitrogen oxides, that are emitted from, among others, the oil and gas industry. Opponents to the new ozone standards challenged the agency's action in federal court. In August 2019, the D.C. Court of Appeals upheld the health-based ozone standards, but remanded to the EPA the secondary, public welfare standards designed to protect environmental values. The 2015 ozone standard is being implemented pursuant to the EPA's December 2018 final implementation rule. In October 2016, the EPA finalized Control Techniques Guidelines for VOC emissions from existing oil and natural gas equipment and processes in moderate ozone non-attainment areas. These Control Techniques Guidelines provide recommendations for states and local air agencies to consider when determining what emissions requirements apply to sources in the non-attainment areas. The EPA has proposed to completely withdraw the rules. On May 12, 2016, the EPA also issued a final rule named the "Source Determination Rule" that was issued to clarify when multiple pieces of oil and gas equipment and activities must be aggregated as a single source for determining whether major source permitting programs apply. This action can expand the permitting and related control requirements to sources that were not previously subject to permitting requirements. However, more recently, the EPA has issued several guidance documents and memorandums related to aggregation of facilities that may narrow the effect of the Source Determination Rule.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third-parties opposing such activities to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. In 2013, a court in California held that the Bureau of Land Management ("BLM") did not comply with NEPA because it did not adequately consider the impact of hydraulic fracturing and horizontal drilling before issuing leases. Courts in New York and Colorado reduced the level of evidence required before a court will agree to consider alleged damage claims from hydraulic fracturing by property owners. Litigation resulting in financial compensation for damages linked to hydraulic fracturing, including damages from induced seismicity, could spur future litigation and bring increased attention to the practice of hydraulic fracturing. Judicial decisions could also lead to increased regulation, permitting requirements, enforcement actions, and penalties. Additional legislation or regulation could also lead to operational delays or restrictions or increased costs in the exploration for, and production of, oil, gas, and NGLs, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional state or local laws, or the implementation of new regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, or an increase in compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows.

Requirements to reduce gas flaring could have an adverse effect on our operations.

Wells in the Midland Basin in Texas, where we have significant operations, produce natural gas, as well as oil and NGLs. Constraints in the gas gathering and processing network in certain areas of the Midland Basin have resulted in significant quantities of that gas being flared instead of gathered, processed, and sold. Further, we are subject to laws established by state and other regulatory agencies that restrict the duration and amount of natural gas that can be legally flared. These laws and regulations, including potential future regulations that may impose further restrictions on flaring, could limit the amount of oil and gas we can produce from our wells or may limit the number of wells or the locations that we can drill. Any future laws and regulations may increase our operational costs, or restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

Our ability to produce oil, gas, and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations and/or completions or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracturing process on which we and others in our industry depend to complete wells that will produce commercial quantities of oil, gas, and NGLs requires the use and disposal of significant quantities of water.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water produced from our wells, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of oil, gas, and NGLs.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil, gas, and NGLs.

In December 2009, the EPA made a finding that emissions of carbon dioxide, methane, and other GHGs endanger public health and the environment because emissions of such gases contribute to warming of the earth’s atmosphere and other climatic changes. Based on this finding, the EPA adopted and implemented a comprehensive suite of regulations to restrict and otherwise regulate emissions of GHGs under existing provisions of the CAA. In particular, the EPA adopted two sets of rules regulating GHG emissions under the CAA. One rule requires a reduction in GHG emissions from motor vehicles, and the other regulates permitting and GHG emissions from certain large stationary sources. These EPA regulatory actions have been challenged by various industry groups, initially in the D.C. Circuit, which in 2012 ruled in favor of the EPA in all respects. However, in June 2014, the United States Supreme Court reversed the D.C. Circuit and struck down the EPA’s GHG permitting rules to the extent they impose a requirement to obtain a permit based solely on emissions of GHGs. The EPA proposed a rule in 2016 to comply with the U.S. Supreme Court’s ruling by limiting the requirement to obtain permits addressing emissions of GHGs to large sources of other air pollutants, such as volatile organic compounds or nitrogen oxides, which also emit 100,000 tons per year or more of CO_2 (or modifications of these sources that result in an emissions increase of 75,000 tons per year or more of CO_2e). If finalized, large sources of air pollutants other than GHGs will be required to implement the best available capture technology for GHGs. However, the EPA has not taken action on the proposed rule and is unlikely to do so under the Trump administration. The EPA has also adopted reporting rules for GHG emissions from specified GHG emission sources in the United States, including petroleum refineries as well as certain onshore oil and gas extraction and production facilities.

Several other cases regarding GHGs have been heard by the courts in recent years. While courts have generally declined to assign direct liability for climate change to large sources of GHG emissions, some have required increased scrutiny of such emissions by federal agencies and permitting authorities. There is a continuing risk of claims being filed against companies that have significant GHG emissions, and new claims for damages and increased government scrutiny, especially from state and local governments, will likely continue. Such cases often seek to challenge air emissions permits that GHG emitters apply for, seek to force emitters to reduce their emissions, or seek damages for alleged climate change impacts to the environment, people, and property. Any court rulings, laws, or regulations that restrict or require reduced emissions of GHGs could lead to increased operating and compliance costs and could have an adverse effect on demand for the oil and gas that we produce.

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states have already taken measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG "cap and trade" programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In 2013, the Congressional Budget Office provided Congress with a study on the potential effects on the United States economy of a tax on GHG emissions and recently summarized the impact of imposition of a tax on GHG emissions for reducing the deficit. While "carbon tax" legislation has been introduced in Congress, the prospects for passage of such legislation are uncertain at this time.

On June 25, 2013, President Obama issued a Climate Action Plan to address climate change through a variety of executive actions, including reduction of methane emissions from oil and gas production and processing operations as well as pipelines and coal mines (the "Climate Action Plan"). Please refer to *Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing, air quality, and greenhouse gas emissions could result in increased costs and additional operating restrictions or delays* for more information on EPA actions to implement the Climate Action Plan. The focus on legislating and/or regulating methane could eventually result in:

- requirements for methane emission reductions from existing oil and gas equipment;
- increased scrutiny for sources emitting high levels of methane, including during permitting processes;
- analysis, regulation and reduction of methane emissions as a requirement for project approval; and
- actions taken by one agency for a specific industry establishing precedents for other agencies and industry sectors.

In relation to the Climate Action Plan, both assumed global warming potential ("GWP") and assumed social costs associated with methane and other GHG emissions have been finalized, including a 20% increase in the GWP of methane. Changes to these measurement tools could adversely impact permitting requirements, application of agencies' existing regulations for source categories with high methane emissions, and determinations of whether a source qualifies for regulation under the CAA. However, in Executive Order 13783, President Trump ordered a review of the use of social cost of carbon for regulatory impact analysis. Therefore, the continued use of the social cost of carbon under the Trump administration is uncertain.

Finally, it should be noted that scientists have predicted that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from flooding or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverage in the aftermath of such events. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies, or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses, or costs that may result from potential physical effects of climate change. Federal regulations or policy changes regarding climate change preparation requirements could also impact our costs and planning requirements.

New technologies may cause our current exploration and drilling methods to become obsolete.

The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services that use new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies we currently use or implement in the future may become obsolete. We cannot be certain we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations, and financial condition may be adversely affected.

Risks Related to Our Common Stock

The price of our common stock may fluctuate significantly, which may result in losses for investors.

From January 1, 2019, to February 6, 2020, the intraday trading prices per share of our common stock as reported by the New York Stock Exchange ranged from a low of $6.85 per share in October 2019 to a high of $21.19 per share in January 2019. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include, in addition to the other risk factors set forth herein, the following:

- changes in oil, gas, or NGL prices;

- changes in the outlook for regional, national, or global commodity supply and demand;
- variations in drilling, recompletion, and operating activity;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel;
- increased volatility due to the impacts of algorithmic trading practices;
- future sales of our common stock;
- changes in the national and global economic outlook, including potential impacts from trade agreements; and
- international trade relationships, potentially including the effects of trade restrictions or tariffs affecting the raw materials we utilize and the commodities we produce in our business.

We may not meet the expectations of our stockholders and/or of securities analysts at some time in the future, and our stock price could decline as a result.

Our certificate of incorporation and by-laws have provisions that discourage corporate takeovers and could prevent stockholders from receiving a takeover premium on their investment, which could adversely affect the price of our common stock.

Delaware corporate law and our certificate of incorporation and by-laws contain provisions that may have the effect of delaying or preventing a change of control of us or our management. These provisions, among other things, provide for non-cumulative voting in the election of members of the Board of Directors and impose procedural requirements on stockholders who wish to make nominations for the election of directors or propose other actions at stockholder meetings. These provisions, alone or in combination with each other, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price investors are willing to pay in the future for shares of our common stock.

In addition, stockholder activism in our industry has been increasing, and if investors seek to exert influence or affect changes to our business that we do not believe are in the long-term best interests of our stockholders, such actions could adversely impact our business by, among other things, distracting our Board of Directors and management team, causing us to incur unexpected advisory fees and other related costs, impacting execution of our strategic objectives, and creating unnecessary market uncertainty.

We may not always pay dividends on our common stock.

Payment of future dividends remains at the discretion of our Board of Directors, and will continue to depend on our earnings, capital requirements, financial condition, and other factors. In addition, the payment of dividends is subject to a covenant in our Credit Agreement limiting our annual cash dividends to no more than $50.0 million, and to covenants in the indentures for our Senior Notes and Senior Convertible Notes that limit our ability to pay dividends beyond a certain amount. Our Board of Directors may determine in the future to reduce the current semi-annual dividend rate of $0.05 per share or discontinue the payment of dividends altogether.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments from the SEC staff regarding our periodic or current reports under the Exchange Act.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our business and operations in the normal course of business. As of the filing of this report, no legal proceedings are pending against us that we believe individually or collectively are likely to have a materially adverse effect upon our financial condition, results of operations or cash flows.

Chieftain Royalty Company v. SM Energy Company, Case No. CIV-11-D, In the United States District Court, Western District of Oklahoma. On January 27, 2011, Chieftain Royalty Company ("Plaintiff") commenced a putative class action lawsuit against the Company by filing a Petition in the District Court of Beaver County, Oklahoma, in the matter originally styled Chieftain Royalty Company v. SM Energy Company (including predecessors, successors and affiliates), Case No. CJ-201104, alleging that the Company had improperly deducted post-production costs from royalty payments due on production from wells located throughout Oklahoma, and asserting claims against the Company for breach of contract, tortious breach of contract, breach of fiduciary or quasi-fiduciary duty, fraud (actual and constructive), deceit, conversion and conspiracy. The Company removed the case to the United States District Court for the Western District of Oklahoma.

On August 2, 2018, the Court required that Plaintiff file any motion to certify a class by February 8, 2019. Plaintiff filed such motion but limited to royalty owners in wells related to the Coal County, Oklahoma pipeline system, which was owned by the Company's affiliate, Four Winds Marketing, LLC, until 2015, when the subject wells and pipeline system were sold to a third party. The Company opposed the Motion and it remains at issue and pending.

This case involves complex legal and factual issues and uncertainties as to Oklahoma law and federal law concerning class certification under the circumstances of this case, and has resulted in a significant amount of discovery. The Company believes that it has properly paid royalties under Oklahoma law and that the class as proposed by Plaintiff should not be certified. The Company has and will continue to vigorously defend this case.

SPM NAM LLC. et al., v. SM Energy Company, Case No. 2018-07160, in the 189th Judicial District of Harris County, Texas (the "Lawsuit"). Plaintiff SPM NAM LLC ("SPM") filed the Lawsuit against the Company on February 1, 2018. The Lawsuit concerns the Acquisition and Development Funding Agreement dated August 2, 2016 (together with its amendments, the "ADFA"). The parties to the ADFA (and its amendments) are the Company; SPM; and certain affiliates of SPM-(1) Schlumberger Technology Corporation; (2) Smith International, Inc.; (3) M-I, L.L.C.; and (4) Cameron International Corporation (the "Schlumberger Service Providers"). In the Lawsuit, SPM and the Schlumberger Service Providers are the plaintiffs, and the Company is the defendant.

In the Lawsuit, SPM alleges that the Company breached the ADFA in connection with the Company's agreement to sell its interests in the Powder River Basin (collectively, the "Company Interests") to a third party ("Buyer"). SPM alleges that pursuant to the ADFA, SPM was entitled to sell its related wellbore interests to Buyer on the same terms and conditions that the Company Interests were to be sold, through a "tag-along" process. SPM alleges that the Company failed to honor the tag-along provisions of the ADFA. The Lawsuit further alleges that the Company fraudulently induced SPM to enter an amendment to the ADFA in connection with its sale. SPM brings claims for rescission, fraud, breach of contract, unjust enrichment, breach of good faith and fair dealing, and declaratory judgment. SPM has not specified the damages it seeks in its pleadings, except to state that they are more than $1,000,000.

The Company has asserted affirmative defenses and counterclaims, that in part allege that: (1) SPM has breached the ADFA by filing an action for rescission, when any rescission remedy is expressly barred by the ADFA; and (2) the Company is entitled to a declaration that the Company has complied with the ADFA; and (3) SPM's tag-along rights under the ADFA expired.

The case is in discovery, and trial is scheduled for June 22, 2020. The Company believes it has complied with the terms of the ADFA, intends to vigorously defend against SPM's claims, and intends to vigorously prosecute its own claims.

ITEM 4. MINE SAFETY DISCLOSURES

These disclosures are not applicable to us.

PART II

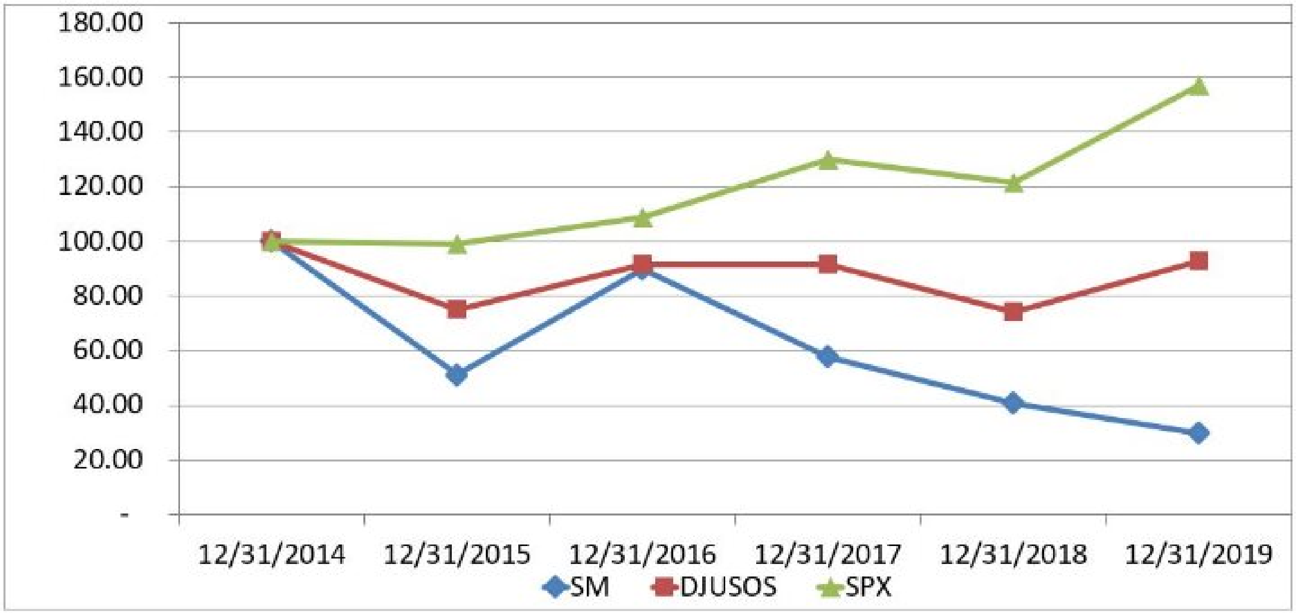
ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information. Our common stock is currently traded on the New York Stock Exchange under the ticker symbol "SM."

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning December 31, 2014, and ending December 31, 2019, with the cumulative total returns of the Dow Jones Exploration and Production Index ("DJUSOS"), and the Standard & Poor's 500 Stock Index ("SPX").

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURNS



The preceding information under the caption Performance Graph shall be deemed to be furnished, but not filed with the SEC.

Holders. As of February 6, 2020, the number of record holders of our common stock was 75. Based upon inquiry, management believes that the number of beneficial owners of our common stock is approximately 17,350.

Purchases of Equity Securities by Issuer and Affiliated Purchasers. The following table provides information about purchases made by us and any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the indicated quarters and year ended December 31, 2019, of shares of our common stock, which is the sole class of equity securities registered by us pursuant to Section 12 of the Exchange Act.

PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS

Period	Total Number of Shares Purchased [(1)]		Weighted Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program [(2)]
01/01/2019 - 03/31/2019	990	$	17.82	—	3,072,184
04/01/2019 - 06/30/2019	154	$	14.91	—	3,072,184
07/01/2019 - 09/30/2019	130,992	$	12.52	—	3,072,184
10/01/2019 - 12/31/2019	—	$	—	—	3,072,184
Total	132,136	$	12.56	—	3,072,184

(1) All shares purchased by us in 2019 were to offset tax withholding obligations that occurred upon the delivery of outstanding shares underlying Restricted Stock Units ("RSUs") issued under the terms of award agreements granted under the SM Energy Equity Incentive Compensation Plan, as amended and restated effective as of May 22, 2018 (the "Equity Plan").

(2) In July 2006, our Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the filing of this report, subject to the approval of our Board of Directors, we may repurchase up to 3,072,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our Credit Agreement, the indentures governing our Senior Notes and Senior Convertible Notes, and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flows, or borrowings under our Credit Agreement. The stock repurchase program may be suspended or discontinued at any time.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected supplemental financial and operating data as of the dates or for the years indicated. The financial data for each of the five years presented was derived from our consolidated financial statements. The following data should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 of this report, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated financial statements included in this report.

	As of or for the Years Ended December 31,				
	2019	**2018**	**2017**	**2016**	**2015**
	(in millions, except per share data)				
Statement of operations data:					
Total operating revenues and other income	$ 1,590.1	$ 2,067.1	$ 1,129.4	$ 1,217.5	$ 1,557.0
Net income (loss)	$ (187.0)	$ 508.4	$ (160.8)	$ (757.7)	$ (447.7)
Net income (loss) per share:					
Basic	$ (1.66)	$ 4.54	$ (1.44)	$ (9.90)	$ (6.61)
Diluted	$ (1.66)	$ 4.48	$ (1.44)	$ (9.90)	$ (6.61)
Cash dividends declared and paid per common share	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10
Balance sheet data:					
Total assets	$ 6,292.2	$ 6,352.9	$ 6,176.8	$ 6,393.5	$ 5,621.6
Long-term debt:					
Revolving credit facility	$ 122.5	$ —	$ —	$ —	$ 202.0
Senior Notes, net of unamortized deferred financing costs	$ 2,453.0	$ 2,448.4	$ 2,769.7	$ 2,766.7	$ 2,316.0
Senior Convertible Notes, net of unamortized discount and deferred financing costs	$ 157.3	$ 147.9	$ 139.1	$ 130.9	$ —

Supplemental Selected Financial and Operations Data

	As of or for the Years Ended December 31,				
	2019	2018	2017	2016	2015
Balance sheet data (in millions):					
Total working capital (deficit)	$ (219.4)	$ (36.8)	$ (10.1)	$ (190.5)	$ 216.5
Total stockholders' equity	$ 2,749.0	$ 2,920.3	$ 2,394.6	$ 2,497.1	$ 1,852.4
Weighted-average common shares outstanding (in thousands):					
Basic	112,544	111,912	111,428	76,568	67,723
Diluted	112,544	113,502	111,428	76,568	67,723
Reserves:					
Oil (MMBbl)	184.1	175.7	158.2	104.9	145.3
Gas (Bcf)	1,223.2	1,321.8	1,280.1	1,111.1	1,264.0
NGLs (MMBbl)	74.0	107.4	96.5	105.7	115.4
MMBOE [(1)]	462.0	503.4	468.1	395.8	471.3
Production and operations (in millions):					
Oil, gas, and NGL production revenue	$ 1,585.8	$ 1,636.4	$ 1,253.8	$ 1,178.4	$ 1,499.9
Oil, gas, and NGL production expense	$ 500.7	$ 487.4	$ 507.9	$ 597.6	$ 723.6
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 823.8	$ 665.3	$ 557.0	$ 790.7	$ 921.0
General and administrative [(2)]	$ 132.8	$ 116.5	$ 117.3	$ 124.8	$ 156.1
Production volumes:					
Oil (MMBbl)	21.9	18.8	13.7	16.6	19.2
Gas (Bcf)	109.8	103.2	123.0	146.9	173.6
NGLs (MMBbl)	8.1	7.9	10.3	14.2	16.1
MMBOE [(1)]	48.3	43.9	44.5	55.3	64.2
Realized price, before the effect of derivative settlements:					
Oil (per Bbl)	$ 54.10	$ 56.80	$ 47.88	$ 36.85	$ 41.49
Gas (per Mcf)	$ 2.39	$ 3.43	$ 3.00	$ 2.30	$ 2.57
NGLs (per Bbl)	$ 17.26	$ 27.22	$ 22.35	$ 16.16	$ 15.92
Per BOE	$ 32.84	$ 37.27	$ 28.20	$ 21.32	$ 23.36
Expense per BOE:					
Lease operating expense	$ 4.67	$ 4.74	$ 4.43	$ 3.51	$ 3.73
Transportation costs	$ 3.88	$ 4.36	$ 5.48	$ 6.16	$ 6.02
Production taxes	$ 1.35	$ 1.52	$ 1.18	$ 0.94	$ 1.13
Ad valorem tax expense	$ 0.48	$ 0.48	$ 0.34	$ 0.21	$ 0.39
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 17.06	$ 15.15	$ 12.53	$ 14.30	$ 14.34
General and administrative [(2)]	$ 2.75	$ 2.65	$ 2.64	$ 2.26	$ 2.43
Statement of cash flows data (in millions):					
Provided by operating activities [(2)]	$ 823.6	$ 720.6	$ 515.4	$ 552.8	$ 990.8
Used in investing activities [(2)]	$ (1,013.3)	$ (587.9)	$ (201.5)	$ (1,867.6)	$ (1,144.6)
Provided by (used in) financing activities [(2)]	$ 111.8	$ (368.7)	$ (12.3)	$ 1,327.2	$ 153.7

(1) Amounts may not calculate due to rounding.
(2) As a result of adopting new accounting standards in prior periods, certain prior period amounts have been reclassified to conform to the current period presentation on the consolidated financial statements.

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

The following discussion includes forward-looking statements. Please refer to the *Cautionary Information about Forward-Looking Statements* section of this report for important information about these types of statements.

Overview of the Company

General Overview

Our purpose is to make people's lives better by responsibly producing energy supplies, contributing to energy security and prosperity, and having a positive impact in the communities where we live and work. Our long-term vision for the Company is to sustainably grow value for all of our stakeholders. We believe that in order to accomplish this vision, we must be a premier operator of top tier assets. At present, our investment portfolio is focused on high quality oil and gas producing assets in the state of Texas, specifically in the Midland Basin of West Texas and in South Texas.

2019 Financial and Operational Highlights

We remain focused on maximizing returns and increasing the value of our top tier Midland Basin and South Texas assets. We expect to do this through continued development optimization and delineation. We believe our assets provide significant production growth potential and strong returns that are capable of increasing internally generated cash flows and support our priorities of improving credit metrics and maintaining strong financial flexibility.

Financial and Operational Results. Average net daily production for the year ended December 31, 2019, was 132.3 MBOE, compared with 120.3 MBOE for the same period in 2018. This increase was primarily driven by a 25 percent increase in production volumes from our Midland Basin assets. Realized prices before the effects of derivative settlements for oil, gas, and NGLs decreased five percent, 30 percent, and 37 percent, respectively, for the year ended December 31, 2019, compared with the year ended December 31, 2018. As a result of decreased realized prices, oil, gas, and NGL production revenue decreased three percent to $1.59 billion for the year ended December 31, 2019, compared with $1.64 billion for 2018. The decrease in oil, gas, and NGL production revenue due to pricing was largely offset by increased production. We recorded a net derivative loss of $97.5 million for the year ended December 31, 2019, compared to a net derivative gain of $161.8 million for the same period in 2018. Included within these derivative amounts is a gain of $39.2 million on derivative contracts that settled during the year ended December 31, 2019, and a loss of $135.8 million for the same period in 2018. Overall financial and operational activities during the year ended December 31, 2019, resulted in the following:

- net loss of $187.0 million, or $1.66 per diluted share, for the year ended December 31, 2019, compared with net income of $508.4 million, or $4.48 per diluted share, for the year ended December 31, 2018. Please refer to *Comparison of Financial Results and Trends Between 2019 and 2018 and Between 2018 and 2017* below for additional discussion regarding the components of net income (loss) for each period presented;

- net cash provided by operating activities was $823.6 million for the year ended December 31, 2019, compared with $720.6 million in 2018, which was an increase of 14 percent year-over-year. Please refer to *Analysis of Cash Flow Changes Between 2019 and 2018 and Between 2018 and 2017* below for additional discussion; and

- adjusted EBITDAX, a non-GAAP financial measure, for the year ended December 31, 2019, was $993.4 million, compared with $900.4 million for the same period in 2018. Please refer to *Non-GAAP Financial Measures* below for additional discussion, including our definition of adjusted EBITDAX and reconciliations to our net income (loss) and net cash provided by operating activities.

Total estimated proved reserves as of December 31, 2019 decreased eight percent from December 31, 2018 to 462.0 MMBOE, of which, 56 percent were liquids (oil and NGLs) and 53 percent were characterized as proved developed. During 2019, we added 98.4 MMBOE through our Midland Basin and South Texas development activities. The 2019 results were partially offset by downward revisions of 94.7 MMBOE primarily resulting from lower commodity prices. Lower commodity prices were also the primary factor in our decreased estimated proved reserve life index, which was 9.6 years at December 31, 2019, compared to 11.5 years at December 31, 2018. Please refer to *Reserves* in Part I, Items 1 and 2 of this report for additional discussion. The standardized measure of discounted future net cash flows was $4.1 billion as of December 31, 2019, compared with $4.7 billion as of December 31, 2018, which was a decrease of 12 percent year-over-year. Please refer to *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional discussion.

Operational Activities. The performance of the RockStar area of our Midland Basin position continues to exceed our pre-acquisition expectations and was key to driving significant growth in our operating margin and cash flows from operations in 2019 due to the high percentage of oil that these wells produce. Our operational execution and development strategy in this region have resulted in strong well performance due to enhanced completion designs and our ability to drill longer laterals given the increasingly contiguous nature of our acreage position as a result of successful infill leasing and acreage trades. Efficiency in completions and operations continued in 2019, as a large portion of our water transportation and disposal needs continue to be satisfied by the water facilities we operate in a core area of our RockStar acreage. We also continued to increase our use of locally sourced sand in our well completions, which has resulted in further cost savings and improved returns for our program.

Our Midland Basin program averaged six drilling rigs and three completion crews during 2019. We completed 123 gross (111 net) operated wells during 2019 and increased production volumes year-over-year by 25 percent to 26.3 MMBOE, 78 percent of which was oil. 82 percent of our total 2019 costs incurred in our oil and gas producing activities was incurred in our Midland Basin program. Drilling and completion activities within our RockStar and Sweetie Peck positions in the Midland Basin continue to focus primarily on delineating and developing the Lower Spraberry and Wolfcamp A and B shale intervals.

Our South Texas program averaged one drilling rig and one completion crew during 2019. We completed 31 gross (20 net) wells during 2019. Total production for 2019 was 22.0 MMBOE, a one percent increase from 2018. 16 percent of our total 2019 costs incurred in our oil and gas producing activities was incurred in our South Texas program. Drilling and completion activities in South Texas continue to focus on developing the Eagle Ford shale formation and delineating the Austin Chalk formation.

Certain drilling and completion activities in the northern portion of our South Texas acreage position were primarily funded by a third party pursuant to our joint development agreement. The agreement provided that the third party would carry substantially all drilling and completion costs and receive a majority of the working and revenue interest in these wells until certain payout thresholds are reached. This arrangement allowed us to leverage third-party capital to prove up the value of our Eagle Ford North area, while also allowing us to test cutting edge technology, capture additional technical data, and satisfy certain lease obligations. All wells subject to this agreement were drilled and completed as of December 31, 2019.

The table below provides a summary of changes in our drilled but not completed well count and current year drilling and completion activity in our operated programs for the year ended December 31, 2019:

	Midland Basin		**South Texas**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Wells drilled but not completed at December 31, 2018	61	55	29	23	90	78
Wells drilled	113	104	25	20	138	124
Wells completed	(123)	(111)	(31)	(20)	(154)	(131)
Other [1]	—	—	(2)	(2)	(2)	(2)
Wells drilled but not completed at December 31, 2019	51	48	21	21	72	69

(1) Includes adjustments related to previously drilled wells that we no longer intend to complete.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed, are summarized as follows:

	For the Year Ended December 31, 2019
	(in millions)
Development costs	$ 914.0
Exploration costs	115.0
Acquisitions	
Proved properties	(0.3)
Unproved properties	11.6
Total, including asset retirement obligations [1]	$ 1,040.2

Note: Total may not calculate due to rounding.

(1) Please refer to the caption *Costs Incurred in Oil and Gas Producing Activities* in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.

All of our development and exploration costs were incurred in our Midland Basin and South Texas programs for the year ended December 31, 2019. Of these costs, $848.6 million was directed to the development of our Midland Basin assets, which resulted in 104 net wells drilled and 111 net wells completed. Comparatively, for the year ended December 31, 2018, $1.1 billion was directed to the development of our Midland Basin assets, which resulted in 117 net wells drilled and 104 net wells completed. Costs incurred for acquisitions during the year related to transactions in the Midland Basin, as well as payments made to extend certain lease terms and to acquire new leases. Please refer to *Operational Activities* above and *Acquisition Activity* below for additional information on our regional activities.

Production Results. The table below presents the disaggregation of our production by product type for each of our operating regions for the year ended December 31, 2019:

	Midland Basin	South Texas	Total
Production:			
Oil (MMBbl)	20.5	1.3	21.9
Gas (Bcf)	34.4	75.4	109.8
NGLs (MMBbl)	—	8.1	8.1
Equivalent (MMBOE)	26.3	22.0	48.3
Avg. daily equivalents (MBOE/d)	72.0	60.3	132.3
Relative percentage	54%	46%	100%

Note: Amounts may not calculate due to rounding.

Production increased 10 percent for the year ended December 31, 2019, compared with 2018. The increase in overall production volumes was primarily attributable to our Midland Basin assets, which had an increase in production volumes of 25 percent for the year ended December 31, 2019, compared with 2018. Please refer to *A Year-to-Year Overview of Selected Production and Financial Information, Including Trends* and *Comparison of Financial Results and Trends Between 2019 and 2018 and Between 2018 and 2017* below for additional discussion on production.

Acquisition Activity. During 2019, while no significant acquisition activity occurred, we completed several non-monetary acreage trades of undeveloped properties located in Howard, Martin, and Midland Counties, Texas, to continue maximizing our operational efficiencies in our Midland Basin program. Please refer to *Note 3 – Divestitures, Assets Held for Sale, and Acquisitions* in Part II, Item 8 of this report for additional discussion.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period, before the effects of derivative settlements, unless otherwise indicated. While quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location, and transportation differentials for these products.

The following table summarizes commodity price data, as well as the effects of derivative settlements, for the years ended December 31, 2019, 2018, and 2017:

	For the Years Ended December 31,		
	2019	2018	2017
Oil (per Bbl):			
Average NYMEX contract monthly price	$ 57.03	$ 64.77	$ 50.95
Realized price, before the effect of derivative settlements	$ 54.10	$ 56.80	$ 47.88
Effect of oil derivative settlements	$ (0.90)	$ (3.67)	$ (2.28)
Gas:			
Average NYMEX monthly settle price (per MMBtu)	$ 2.63	$ 3.09	$ 3.11
Realized price, before the effect of derivative settlements (per Mcf)	$ 2.39	$ 3.43	$ 3.00
Effect of gas derivative settlements (per Mcf)	$ 0.21	$ (0.12)	$ 0.72
NGLs (per Bbl):			
Average OPIS price [(1)]	$ 22.34	$ 32.96	$ 27.63
Realized price, before the effect of derivative settlements	$ 17.26	$ 27.22	$ 22.35
Effect of NGL derivative settlements	$ 4.43	$ (6.78)	$ (3.44)

(1) Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline for all periods presented. This product mix represents the industry standard composite barrel and does not necessarily represent our product mix for NGL production. Realized prices reflect our actual product mix.

We expect future benchmark prices for oil, gas, and NGLs to continue to be volatile due to uncertainty in global supply and demand. In addition to supply and demand fundamentals, as a global commodity, the price of oil is affected by real or perceived geopolitical risks in various regions of the world as well as the relative strength of the United States dollar compared to other currencies. Increased demand for liquefied natural gas and gas exports to Mexico are expected to help balance natural gas supply. NGL prices may continue to benefit from increased demand from export and petrochemical markets while being offset by increased drilling activity. Our realized prices at local sales points may also be affected by infrastructure capacity in the area of our operations and beyond.

The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of February 6, 2020, and December 31, 2019:

	As of February 6, 2020	As of December 31, 2019
NYMEX WTI oil (per Bbl)	$ 51.46	$ 59.01
NYMEX Henry Hub gas (per MMBtu)	$ 2.15	$ 2.28
OPIS NGLs (per Bbl)	$ 18.09	$ 20.00

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives, and decisions regarding entering into derivative commodity contracts are overseen by a financial risk management committee consisting of senior executive officers and finance personnel. The amount of our production covered by derivatives is driven by the amount of debt on our balance sheet, the level of capital commitments and long-term obligations we have in place, and our ability to enter into favorable derivative commodity contracts. With our current derivative commodity contracts, we believe we have partially reduced our exposure to volatility in commodity prices and location differentials in the near term. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil and gas prices while also setting a price floor for a portion of our oil and gas production.

Please refer to *Note 10 – Derivative Financial Instruments* in Part II, Item 8 of this report and to *Commodity Price Risk* in *Overview of Liquidity and Capital Resources* below for additional information regarding our oil, gas, and NGL derivatives.

Outlook

Please refer to *Outlook* in Part I, Item 1 of this report for discussion of our financing and capital plans for 2020, and refer to *Overview of Liquidity and Capital Resources* below for discussion of how we expect to fund our 2020 capital program.

Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information for the three months ended December 31, 2019, and the preceding three quarters.

	For the Three Months Ended			
	December 31, 2019	September 30, 2019	June 30, 2019	March 31, 2019
	(in millions)			
Production (MMBOE)	12.8	12.4	12.4	10.7
Oil, gas, and NGL production revenue	$ 449.0	$ 389.4	$ 406.9	$ 340.5
Oil, gas, and NGL production expense	$ 127.3	$ 129.0	$ 123.1	$ 121.3
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 228.7	$ 211.1	$ 206.3	$ 177.7
Exploration	$ 17.7	$ 11.6	$ 10.9	$ 11.3
General and administrative	$ 37.2	$ 32.6	$ 30.9	$ 32.1
Net income (loss)	$ (102.1)	$ 42.2	$ 50.4	$ (177.6)

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics

	For the Three Months Ended			
	December 31, 2019	September 30, 2019	June 30, 2019	March 31, 2019
Average net daily production equivalent (MBOE per day)	138.8	134.9	136.5	118.7
Lease operating expense (per BOE)	$ 4.67	$ 4.73	$ 4.16	$ 5.20
Transportation costs (per BOE)	$ 3.46	$ 4.00	$ 4.00	$ 4.08
Production taxes as a percent of oil, gas, and NGL production revenue	4.2%	4.1%	4.0%	4.1%
Ad valorem tax expense (per BOE)	$ 0.37	$ 0.39	$ 0.44	$ 0.76
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$ 17.91	$ 17.02	$ 16.61	$ 16.63
General and administrative (per BOE)	$ 2.92	$ 2.63	$ 2.49	$ 3.00

A Year-to-Year Overview of Selected Production and Financial Information, Including Trends

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2019	2018	2017	2019/2018	2018/2017	2019/2018	2018/2017
Net production volumes: (1)							
Oil (MMBbl)	21.9	18.8	13.7	3.1	5.1	17 %	37 %
Gas (Bcf)	109.8	103.2	123.0	6.6	(19.8)	6 %	(16)%
NGLs (MMBbl)	8.1	7.9	10.3	0.2	(2.4)	2 %	(23)%
Equivalent (MMBOE)	48.3	43.9	44.5	4.4	(0.6)	10 %	(1)%
Average net daily production: (1)							
Oil (MBbl per day)	59.9	51.4	37.4	8.5	14.0	17 %	37 %
Gas (MMcf per day)	300.8	282.7	337.0	18.1	(54.3)	6 %	(16)%
NGLs (MBbl per day)	22.2	21.8	28.2	0.5	(6.4)	2 %	(23)%
Equivalent (MBOE per day)	132.3	120.3	121.8	12.0	(1.5)	10 %	(1)%
Oil, gas, and NGL production revenue (in millions): (1)							
Oil production revenue	$ 1,183.2	$ 1,065.7	$ 654.3	$ 117.5	$ 411.4	11 %	63 %
Gas production revenue	262.5	354.5	369.4	(91.9)	(15.0)	(26)%	(4)%
NGL production revenue	140.0	216.2	230.1	(76.2)	(13.9)	(35)%	(6)%
Total oil, gas, and NGL production revenue	$ 1,585.8	$ 1,636.4	$ 1,253.8	$ (50.6)	$ 382.6	(3)%	31 %
Oil, gas, and NGL production expense (in millions): (1)							
Lease operating expense	$ 225.5	$ 208.1	$ 196.9	$ 17.4	$ 11.2	8 %	6 %
Transportation costs	187.1	191.5	243.6	(4.4)	(52.1)	(2)%	(21)%
Production taxes	65.0	66.9	52.4	(1.9)	14.5	(3)%	28 %
Ad valorem tax expense	23.1	20.9	15.0	2.2	5.9	10 %	39 %
Total oil, gas, and NGL production expense	$ 500.7	$ 487.4	$ 507.9	$ 13.3	$ (20.5)	3 %	(4)%
Realized price, before the effect of derivative settlements:							
Oil (per Bbl)	$ 54.10	$ 56.80	$ 47.88	$ (2.70)	$ 8.92	(5)%	19 %
Gas (per Mcf)	$ 2.39	$ 3.43	$ 3.00	$ (1.04)	$ 0.43	(30)%	14 %
NGLs (per Bbl)	$ 17.26	$ 27.22	$ 22.35	$ (9.96)	$ 4.87	(37)%	22 %
Per BOE	$ 32.84	$ 37.27	$ 28.20	$ (4.43)	$ 9.07	(12)%	32 %
Per BOE data:							
Production costs:							
Lease operating expense	$ 4.67	$ 4.74	$ 4.43	$ (0.07)	$ 0.31	(1)%	7 %
Transportation costs	$ 3.88	$ 4.36	$ 5.48	$ (0.48)	$ (1.12)	(11)%	(20)%
Production taxes	$ 1.35	$ 1.52	$ 1.18	$ (0.17)	$ 0.34	(11)%	29 %
Ad valorem tax expense	$ 0.48	$ 0.48	$ 0.34	$ —	$ 0.14	— %	41 %
Total production costs (1)	$ 10.38	$ 11.10	$ 11.43	$ (0.72)	$ (0.33)	(6)%	(3)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 17.06	$ 15.15	$ 12.53	$ 1.91	$ 2.62	13 %	21 %
General and administrative	$ 2.75	$ 2.65	$ 2.64	$ 0.10	$ 0.01	4 %	— %
Derivative settlement gain (loss) (2)	$ 0.81	$ (3.09)	$ 0.48	$ 3.90	$ (3.57)	126 %	(744)%
Earnings per share information:							
Basic weighted-average common shares outstanding (in thousands)	112,544	111,912	111,428	632	484	1 %	— %
Diluted weighted-average common shares outstanding (in thousands)	112,544	113,502	111,428	(958)	2,074	(1)%	2 %
Basic net income (loss) per common share	$ (1.66)	$ 4.54	$ (1.44)	$ (6.20)	$ 5.98	(137)%	415 %
Diluted net income (loss) per common share	$ (1.66)	$ 4.48	$ (1.44)	$ (6.14)	$ 5.92	(137)%	411 %

(1) Amounts and percentage changes may not calculate due to rounding.

(2) Derivative settlements for the years ended December 31, 2019, 2018, and 2017, are included within the net derivative (gain) loss line item in the accompanying consolidated statements of operations ("accompanying statements of operations").

Average net equivalent daily production for the year ended December 31, 2019, increased 10 percent compared with 2018. This increase was primarily driven by a 25 percent increase in production volumes from our Midland Basin assets for the year ended December 31, 2019, compared with 2018. Production volumes from our South Texas assets for the year ended December 31, 2019, were relatively flat compared with 2018. We divested our remaining producing assets in the Rocky Mountain region in the first half of 2018. We expect total production volumes in 2020 to decline slightly compared with 2019; however, we expect total oil volumes to increase. As a result, we expect oil volumes to be approximately 50 percent of our total production mix in 2020. Please refer to *Comparison of Financial Results and Trends Between 2019 and 2018 and Between 2018 and 2017* below for additional discussion.

We present certain information on a per BOE basis in order to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis and discussion.

Our realized price before the effect of derivative settlements on a per BOE basis decreased 12 percent for the year ended December 31, 2019, compared with 2018. This decrease was primarily driven by lower benchmark commodity prices for oil, gas, and NGLs, as well as increased regional differentials in the Midland Basin for natural gas caused by tight takeaway capacity. In the first half of 2019, certain third-party midstream force majeure events negatively affected the price we received for our Midland Basin gas production. Regional differentials for gas in the Midland Basin are expected to continue to negatively affect our realized prices in 2020. Additional expected take-away capacity is anticipated to come online in early 2021. For the year ended December 31, 2019, we recognized a gain of $0.81 per BOE on the settlement of our derivative contracts, compared to a recognized loss of $3.09 per BOE in 2018.

Lease operating expense ("LOE") on a per BOE basis was relatively flat for the year ended December 31, 2019, compared with 2018, despite the increase in oil production as a percentage of our total production. The increase in absolute LOE was primarily driven by increased production. We expect LOE on a per BOE basis to be higher in 2020 compared with 2019 as our product mix continues to shift towards more oil production. We anticipate volatility in LOE on a per BOE basis as a result of changes in total production, our overall production mix, timing of workover projects, and industry activity, all of which impacts service provider costs.

Transportation costs on a per BOE basis decreased 11 percent for the year ended December 31, 2019, compared with 2018. The decrease was driven primarily by an increase in the percentage of production generated from our Midland Basin assets, as production from these assets is typically sold at or near the wellhead and incurs minimal transportation costs. We expect total transportation costs to fluctuate relative to changes in production from our South Texas assets, which incur the majority of our transportation costs. On a per BOE basis, we expect transportation costs to decrease in 2020, compared with 2019, as production from our Midland Basin assets continues to become a larger portion of our total production.

Production taxes on a per BOE basis for the year ended December 31, 2019, decreased 11 percent compared with 2018, primarily due to a 12 percent decrease in our realized price on a per BOE basis before the effect of derivative settlements for the year ended December 31, 2019, compared with 2018. Our overall production tax rate for each of the years ended December 31, 2019, and 2018 was 4.1 percent. We expect our overall production tax rate to remain consistent in 2020, compared with 2019. We generally expect production tax expense to trend with oil, gas, and NGL production revenue on an absolute and per BOE basis. Product mix, the location of production, and incentives to encourage oil and gas development can also impact the amount of production tax we recognize.

Ad valorem tax expense on a per BOE basis for the year ended December 31, 2019, was flat compared with 2018, as the increases on an absolute basis, resulting from changes in our asset and production base, were consistent with higher production volumes. We anticipate volatility in ad valorem tax expense on a per BOE and absolute basis as a result of continuing changes in the valuation of our producing properties.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense on a per BOE basis increased 13 percent for the year ended December 31, 2019, compared with 2018. The increase was driven by our focus on developing oil producing assets in the Midland Basin, which have higher depletion rates than our primarily gas and NGL producing assets in South Texas. Our DD&A rate fluctuates as a result of impairments, divestiture activity, carrying cost funding and sharing arrangements with third parties, changes in our production mix, and changes in our total estimated proved reserve volumes. In general, we expect DD&A expense on a per BOE basis in 2020 to increase compared with 2019 as production from our Midland Basin assets continues to become a larger portion of our total production.

General and administrative ("G&A") expense on a per BOE basis for the year ended December 31, 2019, increased four percent compared with 2018. The increase was primarily due to a reduction in the amount of employee compensation that was reclassified to exploration expense as compared with the prior year, as more employee time was allocated to development activities in 2019. During the fourth quarter of 2019, we announced the reorganization of certain functions to eliminate duplicative regional operational functions and reduce overhead costs, which we expect will result in reduced G&A expense in future years. As a result, we expect to incur total charges related to this reorganization ranging from $8.0 million to $8.5 million, including $4.2 million incurred in the fourth quarter of 2019. We expect G&A expense to decrease in total and on a per BOE basis in 2020 compared with 2019.

Please refer to *Note 9 - Earnings Per Share* in Part II, Item 8 of this report for additional discussion on the types of shares included in our basic and diluted net income (loss) per common share calculations. We recorded a net loss for each of the years ended

December 31, 2019, and 2017. Consequently, all potentially dilutive shares were anti-dilutive and were excluded from the calculation of diluted net loss per common share for the years ended December 31, 2019, and 2017. For the year ended December 31, 2018, we recorded net income and thus considered dilutive shares in the calculation of diluted net income per common share as of December 31, 2018.

Comparison of Financial Results and Trends Between 2019 and 2018 and Between 2018 and 2017

Please refer to *Comparison of Financial Results and Trends Between 2018 and 2017 and Between 2017 and 2016* in *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Part II, Item 7 of our 2018 Annual Report on Form 10-K, filed with the SEC on February 21, 2019, for a detailed discussion of certain comparisons of our financial results and trends for the year ended December 31, 2018, compared with the year ended December 31, 2017.

Net equivalent production, production revenue, and production expense

The following table presents the regional changes in our net equivalent production, production revenue, and production expense between the years ended December 31, 2019, and 2018:

	Net Equivalent Production Increase (Decrease)	Production Revenue Increase (Decrease)	Production Expense Increase (Decrease)
	(MBOE per day)	(in millions)	(in millions)
Midland Basin	14.6	$ 131.1	$ 31.5
South Texas	0.4	(124.5)	5.2
Rocky Mountain [(1)]	(3.1)	(57.2)	(23.3)
Total	12.0	$ (50.6)	$ 13.3

Note: Amounts may not calculate due to rounding.

(1) We divested all remaining producing assets in the Rocky Mountain region in the first half of 2018. As a result, there have been no production volumes from this region after the second quarter of 2018.

We experienced a 10 percent increase in net equivalent production in 2019 compared with 2018, primarily as a result of increased production from our Midland Basin assets. As a result of increased Midland Basin production, oil production as a percentage of our overall product mix increased from 43 percent in 2018, to 45 percent in 2019. Oil, gas, and NGL production revenues decreased three percent for the year ended December 31, 2019, compared with 2018, as a result of lower commodity pricing and the divestiture in the first half of 2018 of our remaining producing assets in the Rocky Mountain region. Total production expense for the year ended December 31, 2019, increased three percent compared with 2018, due to increased LOE and ad valorem tax expense, partially offset by decreased production taxes and transportation costs. Production expense on a per BOE basis decreased six percent for the year ended December 31, 2019, compared with 2018, primarily due to increased production volumes, decreased transportation costs, and decreased production taxes resulting from lower oil, gas, and NGL production revenues.

The following table presents the regional changes in our net equivalent production, production revenue, and production expense between the years ended December 31, 2018 and 2017:

	Net Equivalent Production Increase (Decrease)	Production Revenue Increase (Decrease)	Production Expense Increase (Decrease)
	(MBOE per day)	(in millions)	(in millions)
Midland Basin	27.4	$ 582.5	$ 89.5
South Texas	(20.8)	(95.9)	(64.5)
Rocky Mountain [(1)]	(8.1)	(104.0)	(45.5)
Total	(1.5)	$ 382.6	$ (20.5)

Note: Amounts may not calculate due to rounding.

(1) We divested all remaining producing assets in the Rocky Mountain region in the first half of 2018. As a result, there have been no production volumes from this region after the second quarter of 2018.

We experienced a one percent decrease in net equivalent production in 2018 compared with 2017. The decrease in overall production volumes was a result of decreased production from our operated Eagle Ford shale assets as a result of reduced capital investment, the divestiture of our outside-operated Eagle Ford shale assets which occurred in the first quarter of 2017, and the divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018. Production decreases in the South Texas and Rocky Mountain regions were predominately offset by the 91 percent production volume increase in our Midland Basin assets for the year ended December 31, 2018, compared with 2017. Increased production in the Midland Basin also drove oil production as a percentage of our overall product mix to increase from 31 percent in 2017, to 43 percent in 2018. The increase in higher margin oil production also increased realized prices, before the effects of derivative settlements, on a per BOE basis by 32 percent in 2018, resulting in a 31 percent increase in oil, gas, and NGL production revenue for the year ended 2018 compared with 2017. Production expense in 2018, compared with 2017, decreased four percent, and was primarily driven by the divestiture of the remaining assets in our Rocky Mountain region in the first half of 2018, which had the highest average production costs in our portfolio.

Please refer to *A Year-to-Year Overview of Selected Production and Financial Information, Including Trends* above for discussion of trends on a per BOE basis for the years ended December 31, 2019, 2018, and 2017.

Net gain (loss) on divestiture activity

	For the Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Net gain (loss) on divestiture activity	$ 0.9	$ 426.9	$ (131.0)

No material divestitures occurred during 2019. The $426.9 million net gain on divestiture activity recorded for the year ended December 31, 2018, was the result of a total net gain of $410.6 million recorded for the divestiture of our Powder River Basin assets (the "PRB Divestiture"), which closed in the first quarter of 2018, and a combined total net gain of $15.4 million recorded for the completed divestitures of our remaining assets in the Williston Basin located in Divide County, North Dakota (the "Divide County Divestiture") and our Halff East assets in the Midland Basin (the "Halff East Divestiture"), which closed in the second quarter of 2018.

The net loss on divestiture activity recorded for the year ended December 31, 2017, was primarily the result of $526.5 million of write-downs recorded on certain retained North Dakota assets. These assets were divested in the second quarter of 2018, as discussed above. Partially offsetting these write-downs recorded during 2017, was a $396.8 million total net gain recorded on the sale of our outside-operated Eagle Ford shale assets.

Please refer to *Note 3 – Divestitures, Assets Held for Sale, and Acquisitions* in Part II, Item 8 of this report for additional discussion.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion

	For the Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 823.8	$ 665.3	$ 557.0

DD&A expense for the year ended December 31, 2019, increased 24 percent compared with 2018. DD&A expense for the year ended December 31, 2018, increased 19 percent compared with 2017. These increases are directly related to the 25 percent and 91 percent increases for the years ended December 31, 2019, and 2018, respectively, in production volumes from our Midland Basin assets as these assets have higher depletion rates than our assets in South Texas.

Please refer to *A Year-to-Year Overview of Selected Production and Financial Information, Including Trends* above for discussion of DD&A expense on a per BOE basis.

Exploration

	For the Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Geological and geophysical expenses	$ 2.9	$ 5.6	$ 4.0
Exploratory dry hole	4.8	—	2.4
Overhead and other expenses	43.8	49.6	48.3
Total	$ 51.5	$ 55.2	$ 54.7

Exploration expense decreased seven percent for the year ended December 31, 2019, compared with 2018. The decrease was primarily driven by a reduction in the amount of employee compensation reclassified to exploration expense as more employee time is being allocated to development activities, which is recognized as G&A expense. Exploration expense is impacted by actual geological and geophysical studies we perform and the potential for exploratory dry hole expense.

Impairment of oil and gas properties

	For the Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Impairment of proved properties	$ —	$ —	$ 3.8
Abandonment and impairment of unproved properties	33.8	49.9	12.3
Total	$ 33.8	$ 49.9	$ 16.1

There was no impairment of proved properties expense recognized for the years ended December 31, 2019, and 2018. Unproved property abandonments and impairments recorded for the years ended December 31, 2019, and 2018 related to actual and anticipated lease expirations, as well as actual and anticipated losses on acreage due to title defects, changes in development plans, and other inherent acreage risks.

We expect proved property impairments to occur more frequently in periods of declining or depressed commodity prices, and that the frequency of unproved property abandonments and impairments will fluctuate with the timing of lease expirations or defects, and changing economics associated with decreases in commodity prices. Additionally, changes in drilling plans, unsuccessful exploration activities, and downward engineering revisions may result in proved and unproved property impairments. Future impairments of proved and unproved properties are difficult to predict; however, based on our updated commodity price assumptions as of February 6, 2020, we do not expect any material impairments in the first quarter of 2020 resulting from commodity price impacts. Please refer to *Critical Accounting Policies and Estimates* below for additional discussion.

General and administrative

	For the Years Ended December 31,		
	2019	2018	2017
	(in millions)		
General and administrative	$ 132.8	$ 116.5	$ 117.3

G&A expense increased 14 percent for the year ended December 31, 2019, compared with 2018. Please refer to *A Year-to-Year Overview of Selected Production and Financial Information, Including Trends* above for discussion of G&A expense.

Net derivative (gain) loss

	For the Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Net derivative (gain) loss	$ 97.5	$ (161.8)	$ 26.4

We recognized a net derivative loss of $97.5 million for the year ended December 31, 2019. For contracts that settled during 2019, the fair value was a net asset of $112.2 million at December 31, 2018, and net cash settlements received totaled $39.2 million, resulting in a $73.0 million net loss. Additionally, we recorded a $24.5 million mark-to-market loss on remaining contracts as of December 31, 2019, resulting from an increase in commodity strip prices toward the end of 2019.

We recognized a net derivative gain of $161.8 million for the year ended December 31, 2018. For contracts that settled during 2018, the fair value was a net liability of $108.3 million at December 31, 2017, and net cash settlements paid totaled $135.8 million, resulting in a $27.5 million loss. Offsetting this loss was a $189.3 million mark-to-market gain on remaining contracts as of December 31, 2018, resulting from a decrease in commodity strip prices toward the end of 2018.

We recognized a net derivative loss of $26.4 million for the year ended December 31, 2017. For contracts that settled during 2017, the fair value was a net liability of $60.9 million at December 31, 2016, and net cash settlements received totaled $21.2 million, resulting in an $82.1 million gain. Offsetting this gain was a $108.5 million mark-to-market loss on remaining contracts as of December 31, 2017, resulting from an increase in commodity strip prices.

Please refer to *Note 10 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional discussion.

Interest expense

	For the Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Interest expense	$ (159.1)	$ (160.9)	$ (179.3)

Interest expense for the year ended December 31, 2019, was relatively flat compared with 2018. We expect interest expense related to our Senior Notes to be relatively flat in 2020 compared with 2019; however, total interest expense can vary based on the timing and amount of any borrowings against our credit facility.

The $18.4 million, or 10 percent, decrease in interest expense for the year ended December 31, 2018, compared with 2017, was driven in part by the redemption of our 6.50% Senior Notes due 2021 ("2021 Senior Notes"), which reduced interest expense related to debt in 2018 by $9.4 million compared with 2017. In addition to the overall reduction in debt, interest expense was also reduced as the amount of interest we capitalized increased given our higher level of development activity in 2018 compared with 2017.

Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report and *Overview of Liquidity and Capital Resources* below for additional discussion.

Loss on extinguishment of debt

	For the Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Loss on extinguishment of debt	$ —	$ (26.7)	$ —

For the year ended December 31, 2018, we recorded a $26.7 million net loss on the early extinguishment of our 2021 Senior Notes, 6.50% Senior Notes due 2023 ("2023 Senior Notes"), and a portion of our 6.125% Senior Notes due 2022 ("2022 Senior Notes"). The net loss on extinguishment of debt included $20.4 million associated with the premiums paid upon redemption and repurchase, and $6.3 million related to the acceleration of unamortized deferred financing costs.

Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion.

Income tax (expense) benefit

	For the Years Ended December 31,		
	2019	2018	2017
	(in millions, except tax rate)		
Income tax (expense) benefit	$ 44.0	$ (143.4)	$ 183.0
Effective tax rate	19.1%	22.0%	53.2%

The decrease in the effective tax rate for the year ended December 31, 2019, compared with 2018, was primarily due to the differing effects of permanent items on the loss before income taxes for the year ended December 31, 2019, compared to the impact of these items on income before income taxes for 2018. Excess tax deficiencies from stock-based compensation awards, limits on expensing of certain covered individual's compensation, and other permanent expense items reduced the tax benefit rate for the year ended December 31, 2019. These same items increased the tax expense rate for the year ended December 31, 2018. The reduction in the tax expense rate also reflects a cumulative effect in 2018 from divestitures, and the impact of a correlative change to our state apportionment rate.

The decrease in the effective tax rate for the year ended December 31, 2018, compared with 2017 was primarily due to the impacts of the Tax Cuts and Jobs Act (the "2017 Tax Act"). The 18.5 percent increase in 2017 from a nonrecurring deferred tax adjustment was caused by the 14 percent decrease in the highest marginal corporate rate from 35 percent to 21 percent beginning in 2018. The effect for 2017 was cumulatively added to a tax benefit calculated for that year. The 14 percent decrease is reflected in the 2018 income tax expense rate. In addition, the year-over-year tax rate decreased due to effects related to an excess tax deficiency from stock-based compensation awards, which had the effect of increasing the 2018 tax rate and partially offsetting the year-over-year decrease. Other nominal 2018 tax rate decreases included effects from property sales, net apportionment changes, research credits, and percentage depletion offset by the effects from limits to certain covered individual's compensation.

Please refer to *Overview of Liquidity and Capital Resources* and *Critical Accounting Policies and Estimates* below as well as *Note 4 – Income Taxes* in Part II, Item 8 of this report for further discussion.

Overview of Liquidity and Capital Resources

Based on the current commodity price environment, we believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We continue to manage the duration and level of our drilling and completion service commitments in order to maintain flexibility with regard to our activity level and capital expenditures.

Sources of Cash

We currently expect our 2020 capital program to be funded by cash flows from operations with any remaining cash needs being funded by borrowings under our credit facility. During the year ended December 31, 2019, we generated $823.6 million of cash flows from operating activities. As of December 31, 2019, the remaining available borrowing capacity under our Credit Agreement provided $1.1 billion in liquidity; however, our borrowing base can be adjusted as a result of changes in commodity prices, acquisitions or divestitures of proved properties, or financing activities.

Although we expect cash flows from these sources to be sufficient to fund our expected 2020 capital program, we may also elect to raise funds through new debt or equity offerings or from other sources of financing. If we raise additional funds through the issuance of equity or convertible debt securities, the percentage ownership of our current stockholders could be diluted, and these newly-issued securities may have rights, preferences, or privileges senior to those of existing stockholders. Future downgrades in our credit ratings could make it more difficult or expensive for us to borrow additional funds. Additionally, we may enter into carrying cost and sharing arrangements with third parties for certain exploration or development programs. All of our sources of liquidity can be affected by the general conditions of the broader economy, force majeure events, and fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry.

We have no control over the market prices for oil, gas, or NGLs, although we may be able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. Please refer to *Note 10 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional information about our oil, gas, and NGL derivative contracts currently in place and the timing of settlement of those contracts.

The enactment of the 2017 Tax Act reduced our highest marginal corporate tax rate for 2018 and future years from 35 percent to 21 percent, however future deductibility of interest expense may be limited. In general, the enactment of the 2017 Tax Act has had a positive impact on operating cash flows, and we believe it will positively impact future operating cash flows.

Credit Agreement

Our Credit Agreement provides for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion and is scheduled to mature on September 28, 2023. The maturity date could, however, occur earlier on August 16, 2022, if we have not completed certain repurchase, redemption, or refinancing activities associated with our 2022 Senior Notes, as outlined in the Credit Agreement. No individual bank participating in our Credit Agreement represents more than 10 percent of the lender commitments under the Credit Agreement. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our Credit Agreement as of February 6, 2020, December 31, 2019, and December 31, 2018.

The borrowing base under the Credit Agreement is subject to regular, semi-annual redetermination, and considers the value of both our (a) proved oil and gas properties reflected in the most recent reserve report provided to our lenders under the Credit Agreement; and (b) commodity derivative contracts, each as determined by our lender group. The next scheduled borrowing base redetermination date is April 1, 2020.

We must comply with certain financial and non-financial covenants under the terms of the Credit Agreement, including covenants limiting dividend payments and requiring that we maintain certain financial ratios, as defined by the Credit Agreement. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional detail regarding our financial covenants. We were in compliance with all financial and non-financial covenants as of December 31, 2019, and through the filing of this report.

Our daily weighted-average credit facility debt balance was approximately $115.2 million and $13.1 million for the years ended December 31, 2019, and 2017, respectively. We had no credit facility borrowing activity during 2018 as a result of cash on hand and cash proceeds received during 2018 from divestitures. Cash flows provided by our operating activities, divestiture proceeds, capital markets activities, and the amount of our capital expenditures, including acquisitions, all impact the amount we borrow under our credit facility.

Under our Credit Agreement, borrowings in the form of Eurodollar loans accrue interest based on the London Interbank Offered Rate ("LIBOR"). The use of LIBOR as a global reference rate is expected to be discontinued after 2021. Our Credit Agreement specifies that in the event that LIBOR is no longer a widely used benchmark rate, or that it shall no longer be used for determining interest rates for loans in the United States, a replacement interest rate that fairly reflects the cost to the lenders of funding loans shall be established by the Administrative Agent, as defined in the Credit Agreement, in consultation with us. We currently do not expect the transition from LIBOR to have a material impact on interest expense or borrowing activities under the Credit Agreement, or to otherwise have a material adverse impact on our business.

Weighted-Average Interest and Weighted-Average Borrowing Rates

Our weighted-average interest rate includes paid and accrued interest, fees on the unused portion of the aggregate commitment amount under the Credit Agreement, letter of credit fees, the non-cash amortization of deferred financing costs, and the non-cash amortization of the discount related to the Senior Convertible Notes. Our weighted-average borrowing rate includes paid and accrued interest only.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the years ended December 31, 2019, 2018, and 2017.

	For the Years Ended December 31,		
	2019	2018	2017
Weighted-average interest rate	6.4%	6.4%	6.4%
Weighted-average borrowing rate	5.7%	5.8%	5.8%

Our weighted-average interest rates and weighted average borrowing rates for the years ended December 31, 2019, 2018, and 2017, were impacted by the timing of long-term debt issuances and redemptions and the average outstanding balance on our revolving credit facility. Additionally, our weighted-average interest rates were impacted by the fees paid on the unused portion of our aggregate lender commitments. There was no material change in our weighted-average interest rates or weighted-average borrowing rates for the years ended December 31, 2019, 2018, and 2017. The rates disclosed in the above table do not reflect amounts associated with the repurchase of Senior Notes, such as the discount realized or premium paid upon repurchase, or the acceleration of unamortized deferred financing costs expensed upon repurchase. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion.

Uses of Cash

We use cash for the development, exploration, and acquisition of oil and gas properties and for the payment of operating and general and administrative costs, income taxes, dividends, and debt obligations, including interest. Expenditures for the development, exploration, and acquisition of oil and gas properties are the primary use of our capital resources. During 2019, we spent approximately $1.0 billion on capital expenditures. This amount slightly differs from the costs incurred amount as costs incurred is an accrual-based amount that also includes asset retirement obligations, geological and geophysical expenses, acquisitions of oil and gas properties, and exploration overhead amounts. Please refer to *Costs Incurred in Oil and Gas Producing Activities* in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report for additional discussion.

The amount and allocation of our future capital expenditures will depend upon a number of factors, including the number and size of acquisitions, our cash flows from operating, investing, and financing activities, and our ability to execute our development program. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital, and the timing and results of our exploration and development activities may lead to changes in funding requirements for future development. We periodically review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors.

We may from time to time repurchase or redeem all or portions of our outstanding debt securities for cash, through exchanges for other securities, or a combination of both. Such repurchases or redemptions may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or redemptions will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material. Repurchases or redemptions are reviewed as part of the allocation of our capital. During the third quarter of 2018, we redeemed our 2021 Senior Notes, repurchased or redeemed all of our 2023 Senior Notes, repurchased a portion of our 2022 Senior Notes, and issued our 2027 Senior Notes. We did not conduct similar debt transactions during 2019, or through the filing of this report. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion. As part of our strategy for 2020, we will continue to focus on improving our debt metrics, which could include reducing the amount of our outstanding debt.

As of the filing of this report, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program, subject to the approval of our Board of Directors. Shares may be repurchased from time to time in the open market, or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our Credit Agreement, the indentures governing our Senior Notes, the indenture governing our Senior Convertible Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. Our Board of Directors periodically reviews this program as part of the allocation of our capital. During 2019, we did not repurchase any shares of our common stock, and we currently do not plan to repurchase any outstanding shares of our common stock during 2020.

During the years ended December 31, 2019, 2018, and 2017, we paid $11.3 million, $11.2 million, and $11.1 million, respectively, in dividends to our stockholders, reflecting a dividend of $0.10 per share each year. Our current intention is to continue to make dividend payments for the foreseeable future, subject to our future earnings, our financial condition, Credit Agreement, indentures governing our Senior Notes and Senior Convertible Notes, other covenants, and other factors which could arise. The payment and amount of future dividends remains at the discretion of our Board of Directors.

Analysis of Cash Flow Changes Between 2019 and 2018 and Between 2018 and 2017

The following tables present changes in cash flows between the years ended December 31, 2019, 2018, and 2017, for our operating, investing, and financing activities. The analysis following each table should be read in conjunction with our accompanying consolidated statements of cash flows ("accompanying statements of cash flows") in Part II, Item 8 of this report.

Operating Activities

	For the Years Ended December 31,			Amount Change Between	
	2019	2018	2017	2019/2018	2018/2017
	(in millions)				
Net cash provided by operating activities	$ 823.6	$ 720.6	$ 515.4	$ 103.0	$ 205.2

Derivative settlements increased $202.9 million for the year ended December 31, 2019, compared with 2018. This increase was partially offset by decreased cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes of $73.4 million, and increased cash paid for LOE and ad valorem taxes of $22.0 million for the year ended December 31, 2019, compared with 2018. Cash paid for interest decreased $8.8 million for the year ended December 31, 2019, compared with 2018, due to the redemption and repurchase of certain senior notes in the third quarter of 2018, partially offset by increased interest paid on the 2027 Senior Notes and interest paid on credit facility borrowings during the year ended December 31, 2019. Net cash provided by operating activities is also affected by working capital changes and the timing of cash receipts and disbursements.

Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, increased $196.0 million for the year ended December 31, 2018, compared with 2017, primarily as a result of an increase in our realized price, after the effect of derivative settlements. Interest paid decreased $13.4 million for the year ended December 31, 2018, compared with 2017, due to the redemption and repurchase of certain of our senior notes in the third quarter of 2018. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion.

Investing Activities

	For the Years Ended December 31,			Amount Change Between	
	2019	2018	2017	2019/2018	2018/2017
	(in millions)				
Net cash used in investing activities	$ (1,013.3)	$ (587.9)	$ (201.5)	$ (425.4)	$ (386.4)

Net cash used in investing activities increased for the year ended December 31, 2019, compared with 2018. Proceeds received from the sale of oil and gas properties were $735.5 million lower in 2019 than in 2018 as no material divestitures occurred during 2019. This was partially offset by lower capital expenditures and less cash paid to acquire proved and unproved oil and gas properties of $279.4 million and $30.7 million, respectively.

Net cash used in investing activities increased for the year ended December 31, 2018, compared with 2017. Capital expenditures in 2018 increased $414.8 million compared with 2017, from $888.4 million to $1.3 billion as a result of increased drilling and completion activities. During 2018, cash paid to acquire proved and unproved properties decreased $56.6 million compared with 2017. Further, net proceeds from the sale of oil and gas properties decreased $28.2 million in 2018, compared with 2017. During 2018, net proceeds were primarily from the PRB Divestiture, Divide County Divestiture, and Halff East Divestiture. During 2017, net proceeds were primarily from the sale of our outside-operated Eagle Ford shale assets.

Financing Activities

	For the Years Ended December 31,			Amount Change Between	
	2019	2018	2017	2019/2018	2018/2017
			(in millions)		
Net cash provided by (used in) financing activities	$ 111.8	$ (368.7)	$ (12.3)	$ 480.5	$ (356.4)

Net cash provided by (used in) financing activities increased $480.5 million for year ended December 31, 2019, compared with 2018. During the year ended December 31, 2019, net borrowings under our credit facility increased $122.5 million. We had a zero balance on our credit facility throughout 2018 due to our cash balance resulting from the proceeds received from divestitures in the first half of 2018. During the year ended December 31, 2018, we redeemed or repurchased $824.6 million principal outstanding of certain of our senior notes, and paid premiums totaling $20.4 million in connection with these redemptions and repurchases. Additionally, we issued our 2027 Senior Notes for net proceeds of $492.1 million. There were no such debt transactions during 2019. Please refer to *Note 5 – Long-Term Debt* in Part II, Item 8 of this report for additional discussion.

Interest Rate Risk

We are exposed to market risk due to the floating interest rate associated with any outstanding balance on our revolving credit facility. As of December 31, 2019, we had a $122.5 million balance on our credit facility. Our Credit Agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months. To the extent that the interest rate is fixed, interest rate changes will affect the credit facility's fair value but will not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair value but will impact future results of operations and cash flows. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate Senior Notes or fixed-rate Senior Convertible Notes but can impact their fair values. As of December 31, 2019, our outstanding principal amount of fixed-rate debt totaled $2.6 billion and our floating-rate debt outstanding totaled $122.5 million. Please refer to *Note 11 – Fair Value Measurements* in Part II, Item 8 of this report for additional discussion on the fair values of our Senior Notes and Senior Convertible Notes.

Commodity Price Risk

The prices we receive for our oil, gas, and NGL production directly impact our revenue, profitability, access to capital, and future rate of growth. Oil, gas, and NGL prices are subject to unpredictable fluctuations resulting from a variety of factors, including changes in supply and demand, all of which are typically beyond our control. The markets for oil, gas, and NGLs have been volatile, especially over the last several years, and these markets will likely continue to be volatile in the future. The realized prices we receive for our production also depend on numerous factors that are typically beyond our control. Based on our 2019 production, a 10 percent decrease in our average realized oil, gas, and NGL prices, before the effects of derivative settlements, would have reduced our oil, gas, and NGL production revenues by approximately $118.3 million, $26.3 million, and $14.0 million, respectively. If commodity prices had been 10 percent lower, our net derivative settlements for the year ended December 31, 2019 would have offset the declines in oil, gas, and NGL production revenue by approximately $75.9 million.

We enter into commodity derivative contracts in order to reduce the risk of fluctuations in commodity prices. The fair value of our commodity derivative contracts is largely determined by estimates of the forward curves of the relevant price indices. As of December 31, 2019, a 10 percent increase or decrease in the forward curves associated with our oil, gas, and NGL commodity derivative instruments would have changed our net derivative positions for these products by approximately $113.4 million, $6.4 million, and $3.6 million, respectively.

Schedule of Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2019, for the periods specified (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt [(1)]	$ 2,771.8	$ —	$ 649.3	$ 622.5	$ 1,500.0
Interest payments [(2)]	832.7	160.4	313.2	222.4	136.7
Delivery commitments [(3)]	218.5	46.3	133.7	32.5	6.0
Operating leases and contracts [(3)]	131.1	56.3	34.6	21.5	18.7
Asset retirement obligations [(4)]	114.4	3.1	6.2	36.0	69.1
Derivative liabilities [(5)]	54.6	51.1	3.5	—	—
Other [(6)]	35.6	5.6	14.9	15.1	—
Total	$ 4,158.7	$ 322.8	$ 1,155.4	$ 950.0	$ 1,730.5

(1) Long-term debt consists of the $122.5 million balance on our revolving credit facility, our Senior Notes, and our Senior Convertible Notes and assumes no principal repayment until the maturity dates of these instruments. The actual payment dates may vary significantly.

(2) Interest payments on our Senior Notes and Senior Convertible Notes are estimated assuming no principal repayment until the maturity dates of these instruments. Interest payments on our credit facility have been estimated using the rate applicable to the outstanding balance on our credit facility as of December 31, 2019, and assume no future borrowings or repayments until the September 28, 2023 maturity date of the Credit Agreement. The actual interest payments on our Senior Notes, Senior Convertible Notes, and our credit facility may vary significantly.

(3) Please refer to *Note 6 – Commitments and Contingencies* in Part II, Item 8 of this report for additional discussion regarding our operating leases, contracts, and gathering, processing, transportation throughput, and delivery commitments. The amount relating to our gathering, processing, transportation throughput, and delivery commitments reflects the aggregate undiscounted deficiency payments assuming we delivered no product. This amount does not include any costs that may be incurred for certain contracts where we cannot predict with accuracy the amount and timing of any payments that may be incurred for not meeting certain minimum commitments, as such payments are dependent upon the price of oil in effect at the time of settlement.

(4) Amounts shown represent estimated future undiscounted plugging and abandonment costs. The discounted obligations are recorded as liabilities on our accompanying consolidated balance sheets ("accompanying balance sheets") as of December 31, 2019. The timing and amount of the ultimate settlement of these obligations is unknown and can be impacted by economic factors, a change in development plans, and federal and state regulations. Please refer to *Note 14 – Asset Retirement Obligations* in Part II, Item 8 of this report for additional discussion.

(5) Amounts shown represent only the liability portion of the marked-to-market value of our commodity derivatives based on future market prices as of December 31, 2019, and exclude estimated oil, gas, and NGL commodity derivative receipts. This amount varies from the liability amounts presented on the accompanying balance sheets, as those amounts are presented at fair value, which considers time value, volatility, and the risk of non-performance for us and for our counterparties. The ultimate settlement amounts under our derivative contracts are unknown, as they are subject to continuing market risk and commodity price volatility. Please refer to *Note 10 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional discussion.

(6) The majority of this amount is related to the unfunded portion of our estimated pension liability of $35.2 million, for which we have estimated the timing of future payments based on historical annual contribution amounts.

Off-Balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ("SPEs"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

We evaluate our transactions to determine if any variable interest entities exist. If we determine that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements. We have not been involved in any unconsolidated SPE transactions during 2019 or 2018, or through the filing of this report.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these consolidated financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses, as well as the disclosure of contingent assets and liabilities as of the date of our consolidated financial statements. We base our assumptions and estimates on historical experience and various other sources that we believe to be reasonable under the circumstances. Actual results may differ from the estimates we calculate due to changes in circumstances, global economics and politics, and general business conditions. A summary of our significant accounting policies is detailed in *Note 1 – Summary of Significant Accounting Policies* in Part II, Item 8 of this report. We have outlined below, those policies identified as being critical to the understanding of our business and results of operations and that require the application of significant management judgment.

Successful Efforts Method of Accounting. GAAP provides for two alternative methods for the oil and gas industry to use in accounting for oil and gas producing activities. These two methods are generally known in our industry as the full cost method and the successful efforts method. Both methods are widely used. The methods are different enough that in many circumstances the same set of facts will provide materially different financial statement results within a given year. We have chosen the successful efforts method of accounting for our oil and gas producing activities. A more detailed description is included in *Note 1 – Summary of Significant Accounting Policies* of Part II, Item 8 of this report.

Oil and Gas Reserve Quantities. Our estimated proved reserve quantities and future net cash flows are critical to understanding the value of our business. They are used in comparative financial ratios and are the basis for significant accounting estimates in our consolidated financial statements, including the calculations of depletion and impairment of proved and unproved oil and gas properties. Please refer to *Oil and Gas Producing Activities* in *Note 1 – Summary of Significant Accounting Policies* of Part II, Item 8 of this report for additional discussion on our accounting policies impacted by estimated reserve quantities.

Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure of discounted future net cash flows calculation requires that a 10 percent discount rate be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves. We engage Ryder Scott, an independent reservoir evaluation consulting firm, to audit at least 80 percent of our total calculated proved reserve PV-10. We expect proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. We evaluate and estimate our proved reserves each year end. It should not be assumed that the standardized measure of discounted future net cash flows (GAAP) or PV-10 (non-GAAP) as of December 31, 2019, is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based these measures on a 12-month average of the first-day-of-the-month prices for the year ended December 31, 2019. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimates. Please refer to *Risk Factors - Risks Related to Our Business* in Part I, Item 1A of this report.

If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, which would reduce future net income. Changes in depletion rate calculations caused by changes in reserve quantities are made prospectively. In addition, a decline in reserve estimates may impact the outcome of our assessment of proved and unproved properties for impairment. Impairments are recorded in the period in which they are identified.

The following table presents information about proved reserve changes from period to period due to items we do not control, such as price, and from changes due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	For the Years Ended December 31,		
	2019	2018	2017
	MMBOE Change	MMBOE Change	MMBOE Change
Revisions resulting from performance	(14.9)	(59.7)	7.4
Removal of proved undeveloped reserves no longer in our five-year development plan	(9.8)	(22.6)	(13.9)
Revisions resulting from price changes	(70.0)	13.5	23.1
Total	(94.7)	(68.8)	16.6

As previously noted, commodity prices are volatile and estimates of reserves are inherently imprecise. Consequently, we expect to continue experiencing these types of changes.

We cannot reasonably predict future commodity prices, although we believe that together, the below analyses provide reasonable information regarding the impact of changes in pricing and trends on total estimated proved reserves. The following table reflects the estimated MMBOE change and percentage change to our total reported estimated proved reserve volumes from the described hypothetical changes:

	For the year ended December 31, 2019	
	MMBOE Change	Percentage Change
10 percent decrease in SEC pricing (1)	(7.2)	(2)%
Average NYMEX strip pricing as of fiscal year end (2)	(5.2)	(1)%
10 percent decrease in proved undeveloped reserves (3)	(21.5)	(5)%

(1) The change solely reflects the impact of a 10 percent decrease in SEC pricing to the total reported estimated proved reserve volumes as of December 31, 2019, and does not include additional impacts to our estimated proved reserves that may result from our internal intent to drill hurdles or changes in future service or equipment costs.

(2) The change solely reflects the impact of replacing SEC pricing with the five-year average NYMEX strip pricing as of December 31, 2019. SEC pricing of $55.69 per Bbl for oil, $2.58 per MMBtu for gas, and $22.68 per Bbl for NGLs as of December 31, 2019, compared to the five-year average NYMEX strip pricing of $53.65 per Bbl for oil, $2.42 per MMBtu for gas, and $19.67 per Bbl for NGLs as of December 31, 2019, would result in a one percent decrease to our total reported estimated proved reserve volumes.

(3) The change solely reflects a 10 percent decrease in proved undeveloped reserves as of December 31, 2019, and does not include any additional impacts to our estimated proved reserves.

Additional reserve information can be found in *Reserves* in Part I, Items 1 and 2 of this report, and in *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.

Impairment of Oil and Gas Properties. Proved properties are evaluated periodically for impairment on a pool-by-pool basis when events or changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our oil and gas properties and compare these undiscounted cash flows to the carrying amount to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and gas properties to fair value (or discounted future cash flows). Management estimates future cash flows from all proved reserves and risk adjusted probable and possible reserves using various factors, which are subject to our judgment and expertise, and include, but are not limited to, commodity price forecasts, estimated future operating and capital costs, development plans, and discount rates to incorporate the risk and current market conditions associated with realizing the expected cash flows.

Unproved oil and gas properties are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. Lease acquisition costs that are not individually significant are aggregated by prospect and the portion of such costs estimated to be nonproductive prior to lease expiration are amortized over the appropriate period. The estimate of what could be nonproductive is based on historical trends or other information, including current drilling plans and our intent to renew leases. We estimate the fair value of unproved properties using a market approach, which takes into account the following significant assumptions: remaining lease terms, future development plans, risk weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by us or other market participants.

We cannot predict when or if future impairment charges will be recorded because of the uncertainty in the factors discussed above. Despite any amount of future impairment being difficult to predict, based on our commodity price assumptions as of February 6, 2020, we do not expect any material property impairments in the first quarter of 2020 resulting from commodity price impacts.

Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 11 – Fair Value Measurements* in Part II, Item 8 of this report for discussion of impairments of oil and gas properties recorded for the years ended December 31, 2019, 2018, and 2017.

Asset Retirement Obligations. We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. We base our estimate of the liability on our historical experience in abandoning oil and gas wells and our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the cost, the economic lives and timing of abandonment of our properties, future inflation rates, and the appropriate credit-adjusted risk-free discount rate to use. The impact to the accompanying statements of operations from these estimates is reflected in our depletion, depreciation, and amortization calculations and occurs over the remaining life of our respective oil and gas properties. Please refer to *Note 14 – Asset Retirement Obligations* in Part II, Item 8 of this report for additional discussion.

Revenue Recognition. Effective January 1, 2018, our revenue recognition policy was updated to reflect the adoption of new accounting guidance. Our revenue recognition policy is a critical accounting policy because revenue is a key component of our results of operations and our forward-looking statements contained in our analysis of liquidity and capital resources. Our primary source of revenue is derived by the sale of produced oil, gas, and NGLs. Revenue is recognized at the point in time when custody and title (“control”) of the product, as defined by contractual terms, transfers to the purchaser. Payment for these sales is typically received between 30 and 90 days after the date of production. At the end of each month, we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties, contractual arrangements, historical performance, NYMEX, local spot market, and OPIS prices, and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received are recorded in the month payment is received. A 10 percent change in our revenue accrual at year end 2019 would have impacted total operating revenues by approximately $14.6 million in 2019. Please refer to *Note 2 - Revenue from Contracts with Customers* in Part II, Item 8 of this report for additional discussion.

Derivative Financial Instruments. We periodically enter into commodity derivative contracts to manage our exposure to oil, gas, and NGL price volatility and location differentials. We recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income (loss). The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, option pricing models, futures prices, volatility, time to maturity, and credit risk. The values we report in our consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control. Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 10 – Derivative Financial Instruments* in Part II, Item 8 of this report for additional discussion.

Income Taxes. We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our consolidated financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in predicting when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each period, as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we use and actual amounts we report are recorded in the periods in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery and liability settlement could have an impact on our results of operations. A one percent change in our effective tax rate would have changed our calculated income tax expense by approximately $2.3 million for the year ended December 31, 2019. Please refer to *Note 1 – Summary of Significant Accounting Policies* and *Note 4 – Income Taxes* in Part II, Item 8 of this report for additional discussion.

Accounting Matters

Please refer to *Recently Issued Accounting Standards* in *Note 1 – Summary of Significant Accounting Policies* in Part II, Item 8 of this report for information on new authoritative accounting guidance.

Environmental

We believe we are in substantial compliance with environmental laws and regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, environmental laws and regulations are subject to frequent changes, and we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. For additional information about hydraulic fracturing and related environmental matters, please refer to *Risk Factors – Risks Related to Our Business – Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing, air quality, and greenhouse gas emissions could result in increased costs and additional operating restrictions or delays.*

Climate Change. In June 2013, President Obama announced a Climate Action Plan designed to further reduce GHG emissions and prepare the nation for the physical effects that may occur as a result of climate change. The Climate Action Plan targeted methane reductions from the oil and gas sector as part of a comprehensive interagency methane strategy. As part of the Climate Action Plan, on May 12, 2016, the EPA issued final regulations that amend and expand 2012 regulations for the oil and gas sector by setting emission limits for VOCs and methane, a GHG, and added requirements for previously unregulated sources. The 2016 NSPS requires reduction of methane and VOCs from certain activities in oil and gas production, processing, transmission and storage and applies to facilities constructed, modified, or reconstructed after September 18, 2015. The regulation requires, among other things, GHG and VOC emission limits for certain equipment, such as centrifugal compressors and reciprocating compressors; semi-annual leak detection and repair for well sites and quarterly boosting and garnering compressor stations and gas transmission compressor stations; control requirements and emission limits for pneumatic pumps; and additional requirements for control of GHGs and VOCs from well completions. Both the 2012 and 2016 rules are the subject of Petitions for Review before the U.S. Circuit Court of Appeals for the District of Columbia, although the litigation of both rules has been stayed. In October 2018, the EPA proposed scaling back provisions of the 2016 NSPS directed toward cutting leaks of methane, including proposing allowing only annual inspections for many sites. The rule does not extend to existing sources and the Trump EPA has rescinded the Information Collection Request that was intended to gather information to develop existing source standards. On August 29, 2019, the EPA proposed amendments to the 2012 and 2016 NSPS that would remove transmission and storage infrastructure from regulation of methane emissions and other VOCs. The amendments would also rescind methane requirements for oil and gas production and processing equipment. As an alternative, the EPA proposed to rescind the methane requirements for oil and gas altogether and sought comment on alternative interpretations of its authority to regulate pollutants under Section 111 of the Clean Air Act. On November 16, 2016, the BLM finalized regulations to address methane emissions from oil and gas operations on federal and tribal lands, as part of President Obama's Climate Action Plan. The regulations were intended to reduce the waste of gas from flaring, venting, and leaks by oil and gas production. The rule included requirements that prohibits venting of gas except in limited circumstances and limits flaring of gas and includes requirements for leak detection and repair. The rule also increased royalty payments for "waste" gas that is released in contravention of the rule requirements. After continuous court challenges, the BLM issued a final rule in September 2018 that rescinded most of the 2016 rule, including most of the methane control requirements. Any future regulations requiring similar capture standards may increase our operational costs, or restrict our production, which could materially and adversely affect our financial condition, results of operations, and cash flows.

In August of 2015, the EPA finalized existing source performance standards as stringent state emission "goals" for utilities to reduce GHG emissions. The proposed standards focus on re-dispatching electricity from coal-fired units to gas combined cycle plants and renewables. In February 2016, however, the Supreme Court stayed these rules pending judicial review. The EPA has proposed a repeal of the rule based on a new legal interpretation of the EPA's authority. The EPA proposed a replacement rule, the Affordable Clean Energy Rule, in August 2018 and finalized the rule in June 2019.

The United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In addition, there have been international conventions and efforts to establish standards for the reduction of GHGs globally, including the Paris accords in December 2015. The conditions for entry into force of the

Paris accords were met on October 5, 2016 and the Agreement went into force 30 days later on November 4, 2016. However, in August 2017, the U.S. notified the United Nations Secretary-General that it intends to withdraw from the agreement as soon as it is able to do so, or November 2019. On November 4, 2019, President Trump formally notified the United Nations that the United States would withdraw from the Paris Agreement. The November 4, 2019 formal notice triggered the start of a year-long withdrawal process.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, and results of operations. Judicial challenges to new regulatory measures are likely and we cannot predict the outcome of such challenges. New regulatory suspensions, revisions, or rescissions and conflicting state and federal regulatory mandates may inhibit our ability to accurately forecast the costs associated with future regulatory compliance. Finally, scientists have concluded that increasing concentrations of GHGs in the earth’s atmosphere produce climate changes that likely have significant physical effects, such as increased frequency and severity of storms, droughts, floods, and other climatic events. Such effects could have an adverse effect on our financial condition and results of operations.

In terms of opportunities, the regulation of GHG emissions and the introduction of alternative incentives, such as enhanced oil recovery, carbon sequestration, and low carbon fuel standards, could benefit us in a variety of ways. For example, although federal regulation and climate change legislation could reduce the overall demand for the oil and gas that we produce, the relative demand for gas may increase because the burning of gas produces lower levels of emissions than other readily available fossil fuels such as oil and coal. In addition, if renewable resources, such as wind or solar power become more prevalent, gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply. Also, if states adopt low-carbon fuel standards, gas may become a more attractive transportation fuel. Approximately 38 percent and 39 percent of our production on a BOE basis in 2019 and 2018, respectively, was gas. Market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and gas reservoirs, could also benefit us through the potential to obtain GHG emission allowances or offsets from or government incentives for the sequestration of carbon dioxide.

Non-GAAP Financial Measures

Adjusted EBITDAX represents net income (loss) before interest expense, interest income, income taxes, depletion, depreciation, amortization and asset retirement obligation liability accretion expense, exploration expense, property abandonment and impairment expense, non-cash stock-based compensation expense, derivative gains and losses net of settlements, gains and losses on divestitures, gains and losses on extinguishment of debt, and certain other items. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that we believe provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for development, exploration, acquisitions, and to service debt. We are also subject to financial covenants under our Credit Agreement based on adjusted EBITDAX ratios as further described in the *Credit Agreement* section in *Overview of Liquidity and Capital Resources* above. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies. Our credit facility provides a material source of liquidity for us. Under the terms of our Credit Agreement, if we failed to comply with the covenants that establish a maximum permitted ratio of total funded debt, as defined in the Credit Agreement, to adjusted EBITDAX, we would be in default, an event that would prevent us from borrowing under our credit facility and would therefore materially limit our sources of liquidity. In addition, if we are in default under our credit facility and are unable to obtain a waiver of that default from our lenders, lenders under the credit facility and under the indentures governing our outstanding Senior Notes and Senior Convertible Notes would be entitled to exercise all of their remedies for default.

The following table provides reconciliations of our net income (loss) (GAAP) and net cash provided by operating activities (GAAP) to adjusted EBITDAX (non-GAAP) for the periods presented:

	For the Years Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Net income (loss) (GAAP)	$ (187,001)	$ 508,407	$ (160,843)
Interest expense	159,102	160,906	179,257
Income tax expense (benefit)	(44,043)	143,370	(182,970)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	823,798	665,313	557,036
Exploration [1]	46,995	49,627	48,413
Impairment of oil and gas properties	33,842	49,889	16,078
Stock-based compensation expense	24,318	23,908	22,700
Net derivative (gain) loss	97,539	(161,832)	26,414
Derivative settlement gain (loss)	39,222	(135,803)	21,234
Net (gain) loss on divestiture activity	(862)	(426,917)	131,028
Loss on extinguishment of debt	—	26,740	35
Other, net	481	(3,214)	4,852
Adjusted EBITDAX (non-GAAP)	**993,391**	**900,394**	**663,234**
Interest expense	(159,102)	(160,906)	(179,257)
Income tax (expense) benefit	44,043	(143,370)	182,970
Exploration [1]	(46,995)	(49,627)	(48,413)
Amortization of debt discount and deferred financing costs	15,474	15,258	16,276
Deferred income taxes	(41,835)	141,708	(192,066)
Other, net	1,739	3,501	3,033
Changes in current assets and liabilities	16,852	13,671	69,613
Net cash provided by operating activities (GAAP)	**$ 823,567**	**$ 720,629**	**$ 515,390**

(1) Stock-based compensation expense is a component of the exploration expense and general and administrative expense line items on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations for the component of stock-based compensation expense recorded to exploration expense.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions *Commodity Price Risk* and *Interest Rate Risk* in Item 7 above, as well as under the section entitled *Summary of Oil, Gas, and NGL Derivative Contracts in Place* in *Note 10 – Derivative Financial Instruments* in Part II, Item 8 of this report and is incorporated herein by reference.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of SM Energy Company and subsidiaries

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of SM Energy Company 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 "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at 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 U.S. generally accepted accounting principles.

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 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 20, 2020 expressed an unqualified opinion thereon.

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 regarding 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.

Critical Audit Matter

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

Depletion, depreciation and amortization ('DD&A') of proved oil and gas properties

Description of the Matter	At December 31, 2019, the net book value of the Company's proved oil and gas properties was $4.8 billion, and depletion, depreciation and amortization (DD&A) expense was $823.8 million for the year then ended. As described in Note 1 to the consolidated financial statements, under the successful efforts method of accounting, the costs of development wells are capitalized whether those wells are successful or unsuccessful. Capitalized drilling and completion costs, including lease and well equipment, intangible development costs, and operational support facilities in the field are depleted as a group of assets using the units-of-production method based on proved developed oil and gas reserves, as estimated by the Company's engineering technical team. Similarly, proved leasehold costs are depleted on the same group asset basis; however, the units-of-production method is based on total proved oil and gas reserves, as estimated by the Company's engineering technical team. Significant judgment is required by the Company's engineering technical team in evaluating geoscience and engineering data when estimating proved oil and gas reserves. Estimating reserves also requires the use of inputs, including oil and gas prices and operating and capital costs assumptions, among others. Because of the complexity involved in estimating oil and gas reserves, management used an independent petroleum engineering consulting firm to audit the estimates prepared by the Company's engineering technical team for at least 80% of the Company's total calculated proved reserve PV-10 as of December 31, 2019. Auditing the Company's DD&A calculation is especially complex and judgmental because of our use of the work of the Company's engineering technical team and independent petroleum engineering consulting firm and the evaluation of management's determination of the inputs described above used by the engineering technical team and independent petroleum engineering consulting firm in estimating proved oil and gas reserves.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of controls over the Company's process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to the Company's engineering technical team and independent petroleum engineering consulting firm for use in estimating the proved oil and gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the engineering technical team primarily responsible for overseeing the preparation of the reserve estimates and the independent petroleum engineering consulting firm used to audit the estimates. In addition, in assessing whether we can use the work of the Company's engineering technical team and independent petroleum engineering consulting firm we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineering technical team and independent petroleum engineering consulting firm in estimating proved oil and gas reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. We also tested the mathematical accuracy of the DD&A calculations, including comparing the proved oil and gas reserve amounts used to the Company's reserve report.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2012.
Denver, Colorado
February 20, 2020

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10	$ 77,965
Accounts receivable	184,732	167,536
Derivative assets	55,184	175,130
Prepaid expenses and other	12,708	8,632
Total current assets	252,634	429,263
Property and equipment (successful efforts method):		
Proved oil and gas properties	8,934,020	7,278,362
Accumulated depletion, depreciation, and amortization	(4,177,876)	(3,417,953)
Unproved oil and gas properties	1,005,887	1,581,401
Wells in progress	118,769	295,529
Other property and equipment, net of accumulated depreciation of $64,032 and $57,102, respectively	72,848	93,826
Total property and equipment, net	5,953,648	5,831,165
Noncurrent assets:		
Derivative assets	20,624	58,499
Other noncurrent assets	65,326	33,935
Total noncurrent assets	85,950	92,434
Total assets	**$ 6,292,232**	**$ 6,352,862**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 402,008	$ 403,199
Derivative liabilities	50,846	62,853
Other current liabilities	19,189	—
Total current liabilities	472,043	466,052
Noncurrent liabilities:		
Revolving credit facility	122,500	—
Senior Notes, net of unamortized deferred financing costs	2,453,035	2,448,439
Senior Convertible Notes, net of unamortized discount and deferred financing costs	157,263	147,894
Asset retirement obligations	84,134	91,859
Deferred income taxes	189,386	223,278
Derivative liabilities	3,444	12,496
Other noncurrent liabilities	61,433	42,522
Total noncurrent liabilities	3,071,195	2,966,488
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 112,987,952 and 112,241,966 shares, respectively	1,130	1,122
Additional paid-in capital	1,791,596	1,765,738
Retained earnings	967,587	1,165,842
Accumulated other comprehensive loss	(11,319)	(12,380)
Total stockholders' equity	2,748,994	2,920,322
Total liabilities and stockholders' equity	**$ 6,292,232**	**$ 6,352,862**

The accompanying notes are an integral part of these consolidated financial statements.

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	For the Years Ended December 31,		
	2019	**2018**	**2017**
Operating revenues and other income:			
Oil, gas, and NGL production revenue	$ 1,585,750	$ 1,636,357	$ 1,253,783
Net gain (loss) on divestiture activity	862	426,917	(131,028)
Other operating revenues	3,493	3,798	6,621
Total operating revenues and other income	1,590,105	2,067,072	1,129,376
Operating expenses:			
Oil, gas, and NGL production expense	500,709	487,367	507,906
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	823,798	665,313	557,036
Exploration	51,500	55,166	54,713
Impairment of oil and gas properties	33,842	49,889	16,078
General and administrative	132,797	116,504	117,283
Net derivative (gain) loss	97,539	(161,832)	26,414
Other operating expenses, net	19,888	18,328	13,667
Total operating expenses	1,660,073	1,230,735	1,293,097
Income (loss) from operations	**(69,968)**	**836,337**	**(163,721)**
Interest expense	(159,102)	(160,906)	(179,257)
Loss on extinguishment of debt	—	(26,740)	(35)
Other non-operating income (expense), net	(1,974)	3,086	(800)
Income (loss) before income taxes	**(231,044)**	**651,777**	**(343,813)**
Income tax (expense) benefit	44,043	(143,370)	182,970
Net income (loss)	**$ (187,001)**	**$ 508,407**	**$ (160,843)**
Basic weighted-average common shares outstanding	112,544	111,912	111,428
Diluted weighted-average common shares outstanding	112,544	113,502	111,428
Basic net income (loss) per common share	$ (1.66)	$ 4.54	$ (1.44)
Diluted net income (loss) per common share	$ (1.66)	$ 4.48	$ (1.44)

The accompanying notes are an integral part of these consolidated financial statements.

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	For the Years Ended December 31,		
	2019	**2018**	**2017**
Net income (loss)	$ (187,001)	$ 508,407	$ (160,843)
Other comprehensive income, net of tax:			
Pension liability adjustment [(1)]	1,061	4,378	767
Total other comprehensive income, net of tax	1,061	4,378	767
Total comprehensive income (loss)	**$ (185,940)**	**$ 512,785**	**$ (160,076)**

(1) Please refer to *Note 8 – Pension Benefits* for additional discussion on the pension liability adjustment.

The accompanying notes are an integral part of these consolidated financial statements.

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands, except share data and dividends per share)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
	Shares	Amount				
Balances, January 1, 2017	**111,257,500**	**$ 1,113**	**$ 1,716,556**	**$ 794,020**	**$ (14,556)**	**$ 2,497,133**
Net loss	—	—	—	(160,843)	—	(160,843)
Other comprehensive income	—	—	—	—	767	767
Cash dividends, $ 0.10 per share	—	—	—	(11,144)	—	(11,144)
Issuance of common stock under Employee Stock Purchase Plan	186,665	2	2,621	—	—	2,623
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings	171,278	1	(1,241)	—	—	(1,240)
Stock-based compensation expense	71,573	1	22,699	—	—	22,700
Cumulative effect of accounting change [1]	—	—	1,108	43,624	—	44,732
Other	—	—	(120)	—	—	(120)
Balances, December 31, 2017	**111,687,016**	**$ 1,117**	**$ 1,741,623**	**$ 665,657**	**$ (13,789)**	**$ 2,394,608**
Net income	—	—	—	508,407	—	508,407
Other comprehensive income	—	—	—	—	4,378	4,378
Cash dividends, $0.10 per share	—	—	—	(11,191)	—	(11,191)
Issuance of common stock under Employee Stock Purchase Plan	199,464	2	3,185	—	—	3,187
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings	291,745	3	(2,978)	—	—	(2,975)
Stock-based compensation expense	63,741	—	23,908	—	—	23,908
Cumulative effect of accounting change [1]	—	—	—	2,969	(2,969)	—
Balances, December 31, 2018	**112,241,966**	**$ 1,122**	**$ 1,765,738**	**$ 1,165,842**	**$ (12,380)**	**$ 2,920,322**
Net loss	—	—	—	(187,001)	—	(187,001)
Other comprehensive income	—	—	—	—	1,061	1,061
Cash dividends declared, $0.10 per share	—	—	—	(11,254)	—	(11,254)
Issuance of common stock under Employee Stock Purchase Plan	314,868	3	3,206	—	—	3,209
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings	334,399	4	(1,665)	—	—	(1,661)
Stock-based compensation expense	96,719	1	24,317	—	—	24,318
Balances, December 31, 2019	**112,987,952**	**$ 1,130**	**$ 1,791,596**	**$ 967,587**	**$ (11,319)**	**$ 2,748,994**

(1) Please refer to *Recently Issued Accounting Standards* in *Note 1 – Summary of Significant Accounting Policies* for additional information.

The accompanying notes are an integral part of these consolidated financial statements.

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	For the Years Ended December 31,		
	2019	**2018**	**2017**
Cash flows from operating activities:			
Net income (loss)	$ (187,001)	$ 508,407	$ (160,843)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Net (gain) loss on divestiture activity	(862)	(426,917)	131,028
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	823,798	665,313	557,036
Impairment of oil and gas properties	33,842	49,889	16,078
Stock-based compensation expense	24,318	23,908	22,700
Net derivative (gain) loss	97,539	(161,832)	26,414
Derivative settlement gain (loss)	39,222	(135,803)	21,234
Amortization of debt discount and deferred financing costs	15,474	15,258	16,276
Loss on extinguishment of debt	—	26,740	35
Deferred income taxes	(41,835)	141,708	(192,066)
Other, net	2,220	287	7,885
Changes in current assets and liabilities:			
Accounts receivable	(39,556)	(20,775)	20,410
Prepaid expenses and other	6,130	(729)	(1,953)
Accounts payable and accrued expenses	50,278	35,175	51,156
Net cash provided by operating activities	**823,567**	**720,629**	**515,390**
Cash flows from investing activities:			
Net proceeds from the sale of oil and gas properties	13,059	748,509	776,719
Capital expenditures	(1,023,769)	(1,303,188)	(888,353)
Acquisition of proved and unproved oil and gas properties	(2,581)	(33,255)	(89,896)
Net cash used in investing activities	**(1,013,291)**	**(587,934)**	**(201,530)**
Cash flows from financing activities:			
Proceeds from credit facility	1,589,000	—	406,000
Repayment of credit facility	(1,466,500)	—	(406,000)
Net proceeds from Senior Notes	—	492,079	—
Cash paid to repurchase Senior Notes, including premium	—	(845,002)	(2,357)
Net proceeds from sale of common stock	3,209	3,187	2,623
Dividends paid	(11,254)	(11,191)	(11,144)
Other, net	(2,686)	(7,746)	(1,411)
Net cash provided by (used in) financing activities	**111,769**	**(368,673)**	**(12,289)**
Net change in cash, cash equivalents, and restricted cash	(77,955)	(235,978)	301,571
Cash, cash equivalents, and restricted cash at beginning of period	77,965	313,943	12,372
Cash, cash equivalents, and restricted cash at end of period	**$ 10**	**$ 77,965**	**$ 313,943**
Supplemental schedule of additional cash flow information and non-cash activities:			
Operating activities:			
Cash paid for interest, net of capitalized interest	$ (141,902)	$ (150,727)	$ (164,097)
Net cash (paid) refunded for income taxes	$ 6,109	$ (2,995)	$ (5,986)
Investing activities:			
Changes in capital expenditure accruals and other	$ (24,289)	$ (2,774)	$ 7,309
Supplemental non-cash investing activities:			
Carrying value of properties exchanged	$ 73,442	$ 95,121	$ 293,963
Supplemental non-cash financing activities:			
Non-cash loss on extinguishment of debt, net	$ —	$ 6,334	$ 22

The accompanying notes are an integral part of these consolidated financial statements.

Note 1 – Summary of Significant Accounting Policies

Description of Operations

SM Energy Company, together with its consolidated subsidiaries, is an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in the state of Texas.

Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Company and have been prepared in accordance with GAAP and the instructions to Form 10-K and Regulation S-X. Intercompany accounts and transactions have been eliminated. In connection with the preparation of the consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of December 31, 2019, through the filing of this report. Additionally, certain prior period amounts have been reclassified to conform to current period presentation in the consolidated financial statements.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of proved oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates of proved oil and gas reserve quantities provide the basis for the calculation of depletion, depreciation, and amortization expense, impairment of proved properties, and asset retirement obligations, each of which represents a significant component of the accompanying consolidated financial statements.

Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

Accounts Receivable

The Company’s accounts receivable consists mainly of receivables from oil, gas, and NGL purchasers and from joint interest owners on properties the Company operates. For receivables due from joint interest owners, the Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, the Company’s oil, gas, and NGL receivables are collected within 30 to 90 days and the Company has had minimal bad debts.

Although diversified among many companies, collectibility is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. Receivables are not collateralized. Please refer to *Note 13 – Accounts Receivable and Accounts Payable and Accrued Expenses* for additional disclosure.

Concentration of Credit Risk and Major Customers

The Company is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy related industries. The creditworthiness of customers and other counterparties is subject to regular review.

The Company does not believe the loss of any single purchaser of its production would materially impact its operating results, as oil, gas, and NGLs are products with well-established markets and numerous purchasers in the Company's operating regions. The following major customers and entities under common control accounted for 10 percent or more of its total oil, gas, and NGL production revenue for at least one of the periods presented:

	For the Years Ended December 31,		
	2019	2018	2017
Major customer #1 (1)	18%	18%	6%
Major customer #2 (1)	14%	5%	1%
Major customer #3 (1)	13%	7%	—%
Major customer #4 (1)	9%	10%	10%
Group #1 of entities under common control (2)	13%	18%	17%
Group #2 of entities under common control (2)	11%	12%	8%

(1) These major customers are purchasers of a portion of the Company's production from its Midland Basin assets.
(2) In the aggregate, these groups of entities under common control represented purchasers of more than 10 percent of total oil, gas, and NGL production revenue for at least one of the periods presented; however, no individual entity comprising either group was a purchaser of more than 10 percent of the Company's total oil, gas, and NGL production revenue.

The Company generally contracts with the affiliates of the lenders under its Credit Agreement as its derivative counterparties, and the Company's policy is that each counterparty must have investment grade senior unsecured debt ratings.

The Company maintains its primary bank accounts with a large, multinational bank that has branch locations in the Company's areas of operations. The Company's policy is to diversify its concentration of cash and cash equivalent investments among multiple institutions and investment products to limit the amount of credit exposure to any single institution or investment. The Company maintains investments in highly rated, highly liquid investment products with numerous banks that are party to its revolving credit facility.

Oil and Gas Producing Activities

Proved properties. The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method, the costs of development wells are capitalized whether those wells are successful or unsuccessful. Capitalized drilling and completion costs, including lease and well equipment, intangible development costs, and operational support facilities in the field, are depleted on a group basis (properties aggregated based on geographical and geological characteristics) using the units-of-production method based on estimated proved developed oil and gas reserves. Similarly, proved leasehold costs are depleted on the same group asset basis; however, the units-of-production method is based on estimated total proved oil and gas reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment.

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that associated carrying costs may not be recoverable. The Company uses an income valuation technique, which converts future cash flow to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts, as selected by the Company's management. The Company uses discount rates that are representative of current market conditions and considers estimates of future cash payments, reserve categories, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The discount rates typically range from 10 percent to 15 percent based on the reservoir specific weightings of future estimated proved and unproved cash flows. The prices for oil and gas are forecasted based on NYMEX strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecasted using OPIS pricing, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates.

The partial sale of a proved property within an existing field is accounted for as a normal retirement and no net gain or loss on divestiture activity is recognized as long as the treatment does not significantly affect the units-of-production depletion rate. The sale of a partial interest in an individual proved property is accounted for as a recovery of cost. A net gain or loss on divestiture activity is recognized in the accompanying statements of operations for all other sales of proved properties.

Unproved properties. The unproved oil and gas properties line item on the accompanying balance sheets consists of costs incurred to acquire unproved leases. Leasehold costs allocated to those leases, or partial leases that have associated proved reserves recorded, are reclassified to proved properties and depleted on a units-of-production basis. Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. Lease acquisition costs that are not individually significant are aggregated by prospect and the portion of such costs estimated to be nonproductive prior to lease expiration are amortized over the appropriate period. The estimate of what could be nonproductive is based on historical trends or other information, including current drilling plans and the Company's intent to renew leases. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: remaining lease terms, future development plans, risk-weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by the Company or other market participants.

For the sale of unproved properties where the original cost has been partially or fully amortized by providing a valuation allowance on a group basis, neither a gain nor loss is recognized unless the sales price exceeds the original cost of the property, in which case a gain shall be recognized in the accompanying statements of operations in the amount of such excess.

Exploratory. Exploratory geological and geophysical, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Under the successful efforts method, exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are found, exploratory wells costs will be capitalized as proved properties and will be accounted for following the successful efforts method of accounting described above. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either development or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that economic proved reserves have been discovered may take considerable time and judgment. Exploratory dry hole costs are included in the cash flows from investing activities section as part of capital expenditures within the accompanying statements of cash flows.

Other Property and Equipment

Other property and equipment such as facilities, office furniture and equipment, buildings, and computer hardware and software are recorded at cost. The Company capitalizes certain software costs incurred during the application development stage. The application development stage generally includes software design, configuration, testing, and installation activities. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using either the straight-line method over the estimated useful lives of the assets, which range from 3 to 30 years, or the unit of output method when appropriate. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Other property and equipment costs are evaluated for impairment and reduced to fair value when there is an indication the carrying costs may not be recoverable. To measure the fair value of other property and equipment, the Company uses an income valuation technique or market approach depending on the quality of information available to support management's assumptions and the circumstances. The valuation includes consideration of the proved and unproved assets supported by the property and equipment, future cash flows associated with the assets, and fixed costs necessary to operate and maintain the assets.

Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties, including facilities requiring decommissioning. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is drilled or acquired, or a facility is constructed. The increase in carrying value is included in the proved oil and gas properties line item in the accompanying balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Cash paid to settle asset retirement obligations is included in the cash flows from operating activities section of the accompanying statements of cash flows.

The Company's estimated asset retirement obligation liability is based on historical experience in plugging and abandoning wells, estimated economic lives, estimated plugging and abandonment cost, and federal and state regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company's plugging and abandonment liabilities range from 5.5 percent to 12 percent. In periods subsequent to initial measurement of the liability, the Company must recognize period-to-period changes in the liability resulting from the passage of time, revisions to either the amount of the original estimate of undiscounted cash flows or economic life, or changes in inflation factors or the Company's credit-adjusted risk-free rate as market conditions warrant. Please refer to *Note 14 – Asset Retirement Obligations* for a reconciliation of the Company's total asset retirement obligation liability as of December 31, 2019, and 2018.

Derivative Financial Instruments

The Company periodically enters into commodity derivative instruments to mitigate a portion of its exposure to potentially adverse market changes in commodity prices for its expected future oil, natural gas, and NGL production and the associated impact on cash flows. These instruments typically include commodity price swaps and costless collars, as well as, basis differential swaps. Commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities, with the exception of derivative instruments that meet the "normal purchase normal sale" exclusion. The Company does not designate its derivative commodity contracts as hedging instruments. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its accompanying statements of operations as they occur. Gains and losses on derivatives are included within the cash flows from operating activities section of the accompanying statements of cash flows. For additional discussion on derivatives, please refer to *Note 10 – Derivative Financial Instruments*.

Revenue Recognition

The Company derives revenue primarily from the sale of produced oil, gas, and NGLs. Revenue is recognized at the point in time when custody and title ("control") of the product transfers to the purchaser, which may differ depending on the applicable contractual terms. Revenue accruals are recorded monthly and are based on estimated production delivered to a purchaser and the expected price to be received. Variances between estimates and the actual amounts received are recorded in the month payment is received. Please refer to *Note 2 - Revenue from Contracts with Customers* for additional discussion.

Stock-Based Compensation

At December 31, 2019, the Company had stock-based employee compensation plans that included restricted stock units ("RSUs") and performance share units ("PSUs") issued to employees, RSUs and restricted stock issued to non-employee directors, and an employee stock purchase plan available to eligible employees. These are more fully described in *Note 7 – Compensation Plans.* The Company records expense associated with the fair value of stock-based compensation in accordance with authoritative accounting guidance, which is based on the estimated fair value of these awards determined at the time of grant, and is included within the general and administrative and exploration expense line items in the accompanying statements of operations. For stock-based compensation awards containing non-market based performance conditions, the Company evaluates the probability of the number of shares that are expected to vest, and then adjusts the expense to reflect the number of shares expected to vest and the cumulative vesting period met to date. Further, the Company accounts for forfeitures of stock-based compensation awards as they occur.

Income Taxes

The Company accounts for deferred income taxes whereby deferred tax assets and liabilities are recognized based on the tax effects of temporary differences between the carrying amounts on the consolidated financial statements and the tax basis of assets and liabilities, as measured using current enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recorded or settled, respectively. The Company records deferred tax assets and associated valuation allowances, when appropriate, to reflect amounts more likely than not to be realized based upon Company analysis. Please refer to *Note 4 – Income Taxes* for additional disclosure.

Earnings per Share

The Company uses the treasury stock method to determine the potential dilutive effect of non-vested RSUs, contingent PSUs, and Senior Convertible Notes. Please refer to *Note 9 - Earnings Per Share* for additional discussion.

Comprehensive Income (Loss)

Comprehensive income (loss) is used to refer to net income (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under GAAP are reported as separate components of stockholders' equity instead of net income (loss). Comprehensive income (loss) is presented net of income taxes in the accompanying consolidated statements of comprehensive income (loss) ("accompanying statements of comprehensive income (loss)"). The Company's policy for releasing income tax effects within accumulated other comprehensive loss is an incremental, unit-of-account approach. Please refer to *Note 8 – Pension Benefits* for detail on the changes in the balances of components comprising other comprehensive income (loss).

Fair Value of Financial Instruments

The Company's financial instruments including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The recorded value of the Company's credit facility approximates its fair value as it bears interest at a floating rate that approximates a current market rate. The Company had a $122.5 million balance under its credit facility as of December 31, 2019, compared with a zero balance as of December 31, 2018. The Company's Senior Notes and Senior Convertible Notes are recorded at cost, net of any unamortized discount and deferred financing costs, and their respective fair values are disclosed in *Note 11 – Fair Value Measurements.* Additionally, the Company has derivative financial instruments that are recorded at fair value. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Industry Segment and Geographic Information

The Company operates in the exploration and production segment of the oil and gas industry, onshore in the United States. The Company reports as a single industry segment.

Off-Balance Sheet Arrangements

The Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or SPEs, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

The Company evaluates its transactions to determine if any variable interest entities exist. If it is determined that the Company is the primary beneficiary of a variable interest entity, that entity is consolidated. The Company has not been involved in any unconsolidated SPE transactions in 2019 or 2018.

Recently Issued Accounting Standards

Effective January 1, 2017, the Company adopted, using various transition methods, Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") No. 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* ("ASU 2016-09"). ASU 2016-09 is meant to simplify certain aspects of accounting for share-based arrangements, including income tax effects, accounting for forfeitures, and net share settlements. The Company adopted the various applicable amendments, which are summarized as follows:

- On January 1, 2017, a $44.3 million cumulative-effect adjustment was made to retained earnings and a corresponding deferred tax asset was recorded for previously unrecognized excess tax benefits using a modified retrospective transition method. Effective January 1, 2017, excess tax benefits are presented in net cash provided by operating activities on the accompanying statements of cash flows.

- On January 1, 2017, the Company elected to change its policy to account for forfeitures of share-based payment awards as they occur, rather than applying an estimated forfeiture rate. This change was made using a modified retrospective transition method and resulted in an increase in additional paid-in capital of $1.1 million, a decrease in deferred tax assets of $400,000, and a net $700,000 cumulative effect decrease to retained earnings.

- Under this new guidance, excess tax benefits and deficiencies from share-based payments impact the Company's effective tax rate between periods.

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, followed by other related ASUs that provided targeted improvements and additional practical expedient options (collectively "ASU 2016-02" or "Topic 842"). The Company adopted ASU 2016-02 on January 1, 2019, using the modified retrospective method. The Company elected as part of its adoption to also use the optional transition methodology whereby lease accounting for previously reported periods continues to be reported in accordance with historical accounting guidance for leases in effect for those prior periods. Policy elections and practical expedients the Company implemented in connection with the adoption of ASU 2016-02 include (a) excluding from the balance sheet leases with terms that are less than one year, (b) for agreements that contain both lease and non-lease components, combining these components together and accounting for them as a single lease, (c) the package of practical expedients, which among other requirements, allows the Company to avoid reassessing contracts that commenced prior to adoption that were properly evaluated under legacy GAAP, and (d) excluding land easements that existed or expired before adoption of ASU 2016-02. The scope of ASU 2016-02 does not apply to leases used in the exploration or use of minerals, oil, natural gas, or other similar non-regenerative resources.

Upon adoption on January 1, 2019, the Company recognized approximately $50.0 million in right-of-use ("ROU") assets and related lease liabilities for its operating leases. There was no cumulative effect adjustment to retained earnings upon the adoption of this guidance. Please refer to *Note 12 - Leases* for additional discussion.

In June 2016, the FASB issued ASU No. 2016-13, *Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*, followed by other related ASUs that provided targeted improvements (collectively "ASU 2016-13"). ASU 2016-13 provides financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. The guidance is to be applied using a modified retrospective method and is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. The Company adopted ASU 2016-13 on January 1, 2020. The adoption of ASU 2016-13 is not expected to result in a material impact to the Company's consolidated financial statements or disclosures.

In March 2017, the FASB issued ASU No. 2017-07, *Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* ("ASU 2017-07"). ASU 2017-07 requires presentation of service cost in the same line item(s) as other compensation costs arising from services rendered by employees during the period, and presentation of the remaining components of net benefit cost in a separate line item, outside operating items. In addition, only the service cost component of net benefit cost is eligible for capitalization. The Company adopted ASU 2017-07 on the effective date of January 1, 2018, with retrospective application of the service cost component and the other components of net benefit cost in the consolidated statements of operations, and prospective application for the capitalization of the service cost component of net benefit costs in assets. While the adoption of ASU 2017-07 resulted in the Company reclassifying certain amounts from operating expenses to non-operating expenses, ASU 2017-07 did not result in a material impact to the Company's consolidated financial statements or disclosures.

In February 2018, the FASB issued ASU No. 2018-02, *Income Statement–Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* ("ASU 2018-02"). ASU 2018-02 permits entities to reclassify tax effects stranded in accumulated other comprehensive income (loss) to retained earnings as a result of the 2017 Tax Act. The Company early adopted ASU 2018-02 effective January 1, 2018 using a retrospective method. As a result of adopting ASU 2018-02, the Company reclassified $3.0 million of tax effects stranded in accumulated other comprehensive loss to retained earnings as of January 1, 2018. The Company's policy for releasing income tax effects within accumulated other comprehensive loss is an incremental, unit-of-account approach.

In August 2018, the FASB issued ASU No. 2018-15, *Intangibles-Goodwill and Other-Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract* ("ASU 2018-15"). ASU 2018-15 aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The Company adopted ASU 2018-15 on January 1, 2020, with prospective application. The adoption of ASU 2018-15 is not expected to have a material impact to the Company's consolidated financial statements or disclosures.

In December 2019, the FASB issued ASU No. 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes* ("ASU 2019-12"). ASU 2019-12 was issued as a means to reduce the complexity of accounting for income taxes for those entities that fall within the scope of the accounting standard. The guidance is to be applied using a prospective method, excluding amendments related to franchise taxes, which should be applied on either a retrospective basis for all periods presented or a modified retrospective basis through a cumulative-effect adjustment to retained earnings as of the beginning of the fiscal year of adoption. ASU 2019-12 is effective for fiscal years beginning after December 15, 2020, with early adoption permitted. The Company is evaluating the impact of ASU 2019-12 on its consolidated financial statements.

There are no other ASUs applicable to the Company that would have a material effect on the Company's consolidated financial statements and related disclosures that have been issued but not yet adopted by the Company as of December 31, 2019, and through the filing of this report.

Note 2 - Revenue from Contracts with Customers

The Company recognizes its share of revenue from the sale of produced oil, gas, and NGLs in its Midland Basin and South Texas assets. Following the divestiture of the Company's remaining assets in the Rocky Mountain region during the first half of 2018, there has been no production revenue from this region after the second quarter of 2018. Oil, gas, and NGL production revenue presented within the accompanying statements of operations is reflective of the revenue generated from contracts with customers.

The tables below present the oil, gas, and NGL production revenue by product type for each of the Company's operating regions for the years ended December 31, 2019, 2018, and 2017:

	For the year ended December 31, 2019		
	Midland Basin	South Texas	Total
	(in thousands)		
Oil production revenue	$ 1,119,786	$ 63,426	$ 1,183,212
Gas production revenue	75,827	186,702	262,529
NGL production revenue	123	139,886	140,009
Total	$ 1,195,736	$ 390,014	$ 1,585,750
Relative percentage	75%	25%	100%

Note: Amounts may not calculate due to rounding.

	For the year ended December 31, 2018			
	Midland Basin	South Texas	Rocky Mountain	Total
	(in thousands)			
Oil production revenue	$ 938,004	$ 72,821	$ 54,851	$ 1,065,676
Gas production revenue	125,603	227,252	1,595	354,450
NGL production revenue	1,000	214,441	790	216,231
Total	$ 1,064,607	$ 514,514	$ 57,236	$ 1,636,357
Relative percentage	65%	32%	3%	100%

Note: Amounts may not calculate due to rounding.

	For the year ended December 31, 2017			
	Midland Basin	South Texas	Rocky Mountain	Total
	(in thousands)			
Oil production revenue	$ 419,732	$ 82,674	$ 151,844	$ 654,250
Gas production revenue	61,781	301,780	5,849	369,410
NGL production revenue	547	226,031	3,545	230,123
Total	$ 482,060	$ 610,485	$ 161,238	$ 1,253,783
Relative percentage	38%	49%	13%	100%

Note: Amounts may not calculate due to rounding.

The Company recognizes oil, gas, and NGL production revenue at the point in time when control of the product transfers to the purchaser, which differs depending on the applicable contractual terms. Transfer of control drives the presentation of transportation, gathering, processing, and other post-production expenses ("fees and other deductions") within the accompanying statements of operations. Fees and other deductions incurred by the Company prior to control transfer are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations. When control is transferred at or near the wellhead, sales are based on a wellhead market price that is impacted by fees and other deductions incurred by the purchaser subsequent to the transfer of control. In general, the Company generates production revenue from a combination of the following types of contracts:

- The Company sells oil and gas production at or near the wellhead and receives an agreed-upon market price from the purchaser. Under this type of arrangement, control transfers at or near the wellhead.

- The Company has certain processing arrangements that include the delivery of unprocessed gas to the inlet of a midstream processor's facility for processing. Upon completion of processing, the midstream processor purchases the NGLs and redelivers residue gas back to the Company in-kind. For the NGLs extracted during processing, the midstream processor remits payment to the Company based on the proceeds the processor realizes from selling the NGLs to third parties. For the residue gas taken in-kind, the Company has separate sales contracts where control transfers at points downstream of the processing facility. Given the structure of these arrangements and where control transfers, the Company separately recognizes fees and other deductions incurred prior to control transfer. These fees are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations.

Significant judgments made in applying the guidance in ASC Topic 606, *Revenue from Contracts with Customers,* relate to the point in time when control transfers to customers in gas processing arrangements with midstream processors. The Company does not believe that significant judgments are required with respect to the determination of the transaction price, including amounts that represent variable consideration, as volume and price carry a low level of estimation uncertainty given the precision of volumetric measurements and the use of index pricing with generally predictable differentials. Accordingly, the Company does not consider estimates of variable consideration to be constrained.

The Company's performance obligations arise upon the production of hydrocarbons from wells in which the Company has an ownership interest. The performance obligations are considered satisfied upon control transferring to a purchaser at the wellhead, inlet, or tailgate of the midstream processor's processing facility, or other contractually specified delivery point. The time period between production and satisfaction of performance obligations is generally less than one day; thus, there are no material unsatisfied or partially unsatisfied performance obligations at the end of the reporting period.

Revenue is recorded in the month when performance obligations are satisfied. However, settlement statements from the purchasers of hydrocarbons and the related cash consideration are received 30 to 90 days after production has occurred. As a result, the Company must estimate the amount of production delivered to the customer and the consideration that will ultimately be received for sale of the product. Estimated revenue due to the Company is recorded within the accounts receivable line item on the accompanying balance sheets until payment is received. The accounts receivable balances from contracts with customers within the accompanying balance sheets as of December 31, 2019, and 2018, were $146.3 million and $107.2 million, respectively. To estimate accounts receivable from contracts with customers, the Company uses knowledge of its properties, historical performance, contractual arrangements, index pricing, quality and transportation differentials, and other factors as the basis for these estimates. Differences between estimates and actual amounts received for product sales are recorded in the month that payment is received from the purchaser.

Note 3 – Divestitures, Assets Held for Sale, and Acquisitions

2019 Divestiture Activity

No material divestitures occurred during 2019.

2018 Divestiture Activity

PRB Divestiture. On March 26, 2018, the Company completed the PRB Divestiture, divesting of approximately 112,000 net acres for total cash received at closing, net of costs (referred to throughout this report as "net divestiture proceeds"), of $492.2 million, and recorded a final net gain of $410.6 million for the year ended December 31, 2018.

Divide County Divestiture and Halff East Divestiture. During the second quarter of 2018, the Company completed the Divide County Divestiture and the Halff East Divestiture, for combined net divestiture proceeds of $252.2 million, and recorded a combined final net gain of $15.4 million for the year ended December 31, 2018.

The following table presents loss before income taxes from the Divide County, North Dakota assets sold for the years ended December 31, 2019, 2018, and 2017. The Divide County Divestiture was considered a disposal of a significant asset group.

	For the Years Ended December 31,		
	2019	2018	2017
	(in thousands)		
Loss before income taxes [1]	$ —	$ (28,975)	$ (468,786)

[1] Loss before income taxes reflects oil, gas, and NGL production revenue, less oil, gas, and NGL production expense, depletion, depreciation, amortization, and asset retirement obligation liability accretion expense, impairment expense, and net loss on divestiture activity. During the year ended December 31, 2017, the Company recorded a write-down of $523.6 million on these assets.

2017 Divestiture Activity

Eagle Ford Divestiture. On March 10, 2017, the Company divested its outside-operated Eagle Ford shale assets, including its ownership interest in related midstream assets, for final net divestiture proceeds of $744.1 million. The Company recorded a final net gain of $396.8 million related to these divested assets for the year ended December 31, 2017. This divestiture was considered a disposal of a significant asset group. For the year ended December 31, 2017, income before income taxes from the outside-operated Eagle Ford shale assets sold was $24.3 million. This amount reflects oil, gas, and NGL production revenue, less oil, gas, and NGL production expense, and depletion, depreciation, amortization, and asset retirement obligation liability accretion expense.

During 2017, the Company divested certain non-core properties for net divestiture proceeds of $36.2 million and recognized an insignificant final net gain.

The Company determined that executed asset sales in 2018 and 2017 did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

2019 Acquisition Activity

During 2019, the Company completed several non-monetary acreage trades of primarily undeveloped properties located in Howard, Martin, and Midland Counties, Texas, resulting in the exchange of approximately 2,200 net acres, with $73.4 million of carrying value attributed to the properties transferred by the Company. These trades were recorded at carryover basis with no gain or loss recognized.

2018 Acquisition Activity

During the year ended December 31, 2018, the Company acquired approximately 1,030 net acres of primarily unproved properties located in Martin and Howard Counties, Texas, in two separate transactions which closed in 2018. Combined total cash consideration paid by the Company was $33.3 million. Under authoritative accounting guidance, these transactions were both individually considered to be asset acquisitions. Therefore, the properties were recorded based on the fair value of the total consideration transferred on the acquisition date and the transaction costs were capitalized as a component of the cost of the assets acquired.

During the third quarter of 2018, the Company completed two non-monetary acreage trades of primarily undeveloped properties located in Howard and Martin Counties, Texas, which resulted in the exchange of approximately 2,650 net acres, with $95.1 million of carrying value attributed to the properties transferred by the Company. These trades were recorded at carryover basis with no gain or loss recognized.

2017 Acquisition Activity

During the year ended December 31, 2017, the Company acquired approximately 3,600 net acres of primarily unproved properties in Howard and Martin Counties, Texas, in multiple transactions for a total of $76.5 million of cash consideration. Under authoritative accounting guidance, these transactions were individually considered to be asset acquisitions. Therefore, the properties were recorded based on the fair value of the total consideration transferred on the acquisition date and the transaction costs were capitalized as a component of the cost of the assets acquired.

Also during the year ended December 31, 2017, the Company completed several non-monetary acreage trades of primarily unproved properties in Howard and Martin Counties, Texas, resulting in the exchange of approximately 8,125 net acres for approximately 7,580 net acres with $294.0 million of carrying value attributed to the properties transferred by the Company in such trades. These trades were recorded at carryover basis with no gain or loss recognized.

Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2019	2018	2017
		(in thousands)	
Current portion of income tax expense (benefit)			
Federal	$ (3,826)	$ —	$ 5,698
State	1,618	1,662	3,398
Deferred portion of income tax expense (benefit)	(41,835)	141,708	(192,066)
Income tax expense (benefit)	$ (44,043)	$ 143,370	$ (182,970)
Effective tax rate	19.1%	22.0%	53.2%

The components of the net deferred tax liabilities are as follows:

	As of December 31,	
	2019	2018
	(in thousands)	
Deferred tax liabilities		
Oil and gas properties	$ 205,028	$ 218,094
Derivative assets	4,646	35,247
Other	12,361	4,812
Total deferred tax liabilities	222,035	258,153
Deferred tax assets		
Credit carryover	11,270	22,554
Pension	5,971	6,427
Federal and state tax net operating loss carryovers	4,172	4,217
Stock compensation	3,503	3,263
Other liabilities	10,803	1,497
Total deferred tax assets	35,719	37,958
Valuation allowance	(3,070)	(3,083)
Net deferred tax assets	32,649	34,875
Total net deferred tax liabilities	$ 189,386	$ 223,278
Current federal income tax refundable	$ 3,885	$ 59
Current state income tax payable	$ 1,404	$ 1,331

As of December 31, 2019, the Company estimated its federal net operating loss (“NOL”) carryforward at $3.3 million and state NOL carryforwards at $77.8 million. The Company has federal research and development (“R&D”) and AMT credit carryforwards of $7.4 million and $4.3 million, respectively. The majority of federal NOLs do not expire but the state NOLs and state tax credits expire between 2021 and 2038. The federal R&D credit carryforwards expire between 2028 and 2035. The Company’s AMT credit carryforwards are expected to be fully refunded by 2022. The Company’s current valuation allowance relates to state NOL carryforwards and state tax credits, which are expected to expire before they can be utilized.

Recorded income tax expense or benefit differs from the amount that would be provided by applying the statutory United States federal income tax rate to income before income taxes. These differences primarily relate to the effect of state income taxes, excess tax benefits and deficiencies from stock-based compensation awards, tax limitations on compensation of covered individuals, changes in valuation allowances, and the cumulative impact of other smaller permanent differences, and is reported as follows:

	For the Years Ended December 31,		
	2019	2018	2017
		(in thousands)	
Federal statutory tax expense (benefit)	$ (48,519)	$ 136,873	$ (120,335)
Increase (decrease) in tax resulting from:			
Federal tax reform changes - 2017 Tax Act	—	—	(63,675)
State tax expense (benefit) (net of federal benefit)	260	2,771	(3,286)
Change in valuation allowance	(13)	105	(2,727)
Employee share-based compensation	3,346	2,508	8,190
Other	883	1,113	(1,137)
Income tax expense (benefit)	$ (44,043)	$ 143,370	$ (182,970)

Acquisitions, divestitures, drilling activity, and basis differentials, which impact the prices received for oil, gas, and NGLs, impact the apportionment of taxable income to the states where the Company owns oil and gas properties. As these factors change, the Company’s state income tax rate changes. This change, when applied to the Company’s total temporary differences, impacts the total state income tax expense (benefit) reported in the current year. Items affecting state apportionment factors are evaluated upon completion of the prior year income tax return, after significant acquisitions and divestitures, if there are significant changes in drilling activity, or if estimated state revenue changes occur during the year. As a result of the 2018 divestitures, the Company’s state apportionment rate reflects its significant Texas presence.

During the fourth quarter of 2019, the Company claimed and received a $7.7 million refund for a portion of its deferred AMT credit carryover. An additional refund of $3.8 million is expected to be claimed in 2020. For all years before 2015, the Company is generally no longer subject to United States federal or state income tax examinations by tax authorities.

The Company complies with authoritative accounting guidance regarding uncertain tax provisions. The entire amount of unrecognized tax benefit reported by the Company would affect its effective tax rate if recognized. Interest expense in the accompanying statements of operations includes a negligible amount associated with income taxes. The Company does not expect a significant change to the recorded unrecognized tax benefits in 2020.

The total amount recorded for unrecognized tax benefits for each of the years ended December 31, 2019, 2018, and 2017, was $446,000.

Note 5 – Long-Term Debt

Credit Agreement

On September 19, 2019, the Company and its lenders entered into the Second Amendment to the Sixth Amended and Restated Credit Agreement which permitted the Company to enter into swap agreements with respect to the price of electricity in order to minimize exposure to electrical price volatility. As of December 31, 2019, the Credit Agreement provided for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion, a borrowing base of $1.6 billion, and aggregate lender commitments of $1.2 billion. The borrowing base is subject to regular, semi-annual redetermination, and considers the value of both the Company's (a) proved oil and gas properties reflected in the Company's most recent reserve report; and (b) commodity derivative contracts, each as determined by the Company's lender group. The next scheduled borrowing base redetermination date is April 1, 2020.

The Credit Agreement is scheduled to mature on the earlier of September 28, 2023, (the "Scheduled Maturity Date"), and August 16, 2022, to the extent that, on or before such date, the Company's outstanding 2022 Senior Notes are not repurchased, redeemed, or refinanced to have a maturity date at least 91 days after the Scheduled Maturity Date unless, on August 16, 2022, both (i) the aggregate outstanding principal amount of the 2022 Senior Notes is not more than $100.0 million and (ii) after giving pro forma effect to the repayment in full at maturity of the 2022 Senior Notes then outstanding, the aggregate amount of unrestricted cash and certain types of unrestricted investments held by the Company and its Consolidated Restricted Subsidiaries plus the amount of unused availability under the Credit Agreement is at least $300.0 million.

The Company must comply with certain financial and non-financial covenants under the terms of the Credit Agreement, including covenants limiting dividend payments and requiring the Company to maintain certain financial ratios, as defined by the Credit Agreement. The financial covenants under the Credit Agreement require that the Company's (a) total funded debt, as defined in the Credit Agreement, to adjusted EBITDAX ratio for the most recently ended four consecutive fiscal quarters (excluding the first three quarters which used annualized adjusted EBITDAX), cannot be greater than 4.25 to 1.00 beginning with the quarter ending December 31, 2018, through and including the fiscal quarter ending December 31, 2019, and for each quarter ending thereafter, the ratio cannot be greater than 4.00 to 1.00; and (b) adjusted current ratio cannot be less than 1.0 to 1.0 as of the last day of any fiscal quarter. The Company was in compliance with all financial and non-financial covenants as of December 31, 2019, and through the filing of this report.

Interest and commitment fees associated with the credit facility are accrued based on a borrowing base utilization grid set forth in the Credit Agreement. At the Company's election, borrowings under the Credit Agreement may be in the form of Eurodollar, Alternate Base Rate ("ABR"), or Swingline loans. Eurodollar loans accrue interest at LIBOR, plus the applicable margin from the utilization grid, and ABR and Swingline loans accrue interest at a market-based floating rate, plus the applicable margin from the utilization grid. Commitment fees are accrued on the unused portion of the aggregate lender commitment amount at rates from the utilization grid and are included in the interest expense line item on the accompanying statements of operations. The borrowing base utilization grid as set forth in the Credit Agreement is as follows:

Borrowing Base Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
Eurodollar Loans [(1)]	1.500%	1.750%	2.000%	2.250%	2.500%
ABR Loans or Swingline Loans	0.500%	0.750%	1.000%	1.250%	1.500%
Commitment Fee Rate	0.375%	0.375%	0.500%	0.500%	0.500%

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(1) The Company's Credit Agreement specifies that in the event that LIBOR is no longer a widely used benchmark rate, or that it shall no longer be used for determining interest rates for loans in the United States, a replacement interest rate that fairly reflects the cost to the lenders of funding loans shall be established by the Administrative Agent, as defined in the Credit Agreement, in consultation with the borrower.

The following table presents the outstanding balance, total amount of letters of credit outstanding, and available borrowing capacity under the Credit Agreement as of February 6, 2020, December 31, 2019, and December 31, 2018:

	As of February 6, 2020	As of December 31, 2019	As of December 31, 2018
	(in thousands)		
Revolving credit facility [(1)]	$ 113,500	$ 122,500	$ —
Letters of credit [(2)]	—	—	200
Available borrowing capacity	1,086,500	1,077,500	999,800
Total aggregate lender commitment amount	$ 1,200,000	$ 1,200,000	$ 1,000,000

(1) Unamortized deferred financing costs attributable to the revolving credit facility are presented as a component of the other noncurrent assets line item on the accompanying balance sheets and totaled $5.9 million and $6.4 million as of December 31, 2019, and 2018, respectively. These costs are being amortized over the term of the credit facility on a straight-line basis.

(2) Letters of credit outstanding reduce the amount available under the credit facility on a dollar-for-dollar basis. The letter of credit outstanding as of December 31, 2018, was released effective January 8, 2019.

Senior Notes

The Senior Notes, net of unamortized deferred financing costs line item on the accompanying balance sheets as of December 31, 2019, and 2018, consisted of the following:

	As of December 31,					
	2019			2018		
	Principal Amount	Unamortized Deferred Financing Costs	Principal Amount, Net of Unamortized Deferred Financing Costs	Principal Amount	Unamortized Deferred Financing Costs	Principal Amount, Net of Unamortized Deferred Financing Costs
	(in thousands)					
6.125% Senior Notes due 2022	$ 476,796	$ 2,920	$ 473,876	$ 476,796	$ 3,921	$ 472,875
5.0% Senior Notes due 2024	500,000	3,766	496,234	500,000	4,688	495,312
5.625% Senior Notes due 2025	500,000	4,903	495,097	500,000	5,808	494,192
6.75% Senior Notes due 2026	500,000	5,571	494,429	500,000	6,407	493,593
6.625% Senior Notes due 2027	500,000	6,601	493,399	500,000	7,533	492,467
Total	$ 2,476,796	$ 23,761	$ 2,453,035	$ 2,476,796	$ 28,357	$ 2,448,439

The Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the Senior Notes. The Company is subject to certain covenants under the indentures governing the Senior Notes that limit the Company's ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends. The Company was in compliance with all such covenants under its Senior Notes as of December 31, 2019, and through the filing of this report. All Senior Notes are registered under the Securities Act. The Company may redeem some or all of its Senior Notes prior to their maturity at redemption prices based on a premium, plus accrued and unpaid interest as described in the indentures governing the Senior Notes.

On July 16, 2018, the Company redeemed its 2021 Senior Notes which resulted in the payment of total cash consideration, including accrued interest, of $355.9 million. Additionally, during the third quarter of 2018, the Company used the proceeds from the issuance of its 2027 Senior Notes, as discussed below, and cash on hand to fund the cash tender offer and redemption of $395.0 million of its 2023 Senior Notes and $85.0 million of its 2022 Senior Notes. The Company paid total consideration, including accrued interest, of $497.8 million to complete these transactions. As a result of the redemption of the 2021 Senior Notes, and the cash tender offer and redemption of all of the 2023 Senior Notes and a portion of the 2022 Senior Notes, the Company recorded a combined loss on extinguishment of debt of $26.7 million for the year ended December 31, 2018. This amount included combined premiums paid of $20.4 million and $6.3 million of accelerated unamortized deferred financing costs for the redemption.

2022 Senior Notes. On November 17, 2014, the Company issued $600.0 million in aggregate principal amount of 6.125% Senior Notes due 2022 at par, which mature on November 15, 2022. The Company received net proceeds of $590.0 million after deducting fees of $10.0 million, which are being amortized as deferred financing costs over the life of the 2022 Senior Notes. During the first quarter of 2016, the Company repurchased $38.2 million in aggregate principal amount of its 2022 Senior Notes for a settlement amount of $24.3 million, excluding interest. During the third quarter of 2018, through the tender offer discussed above, the Company retired $85.0 million of its 2022 Senior Notes for total consideration, including accrued interest, of $89.5 million.

2024 Senior Notes. On May 20, 2013, the Company issued $500.0 million in aggregate principal amount of 5.0% Senior Notes due 2024 at par, which mature on January 15, 2024. The Company received net proceeds of $490.2 million after deducting fees of $9.8 million, which are being amortized as deferred financing costs over the life of the 2024 Senior Notes.

2025 Senior Notes. On May 21, 2015, the Company issued $500.0 million in aggregate principal amount of 5.625% Senior Notes due 2025 at par, which mature on June 1, 2025. The Company received net proceeds of $491.0 million after deducting fees of $9.0 million, which are being amortized as deferred financing costs over the life of the 2025 Senior Notes.

2026 Senior Notes. On September 12, 2016, the Company issued $500.0 million in aggregate principal amount of 6.75% Senior Notes due 2026, at par, which mature on September 15, 2026. The Company received net proceeds of $491.6 million after deducting fees of $8.4 million, which are being amortized as deferred financing costs over the life of the 2026 Senior Notes.

2027 Senior Notes. On August 20, 2018, the Company issued $500.0 million in aggregate principal amount of 6.625% Senior Notes due 2027, at par, which mature on January 15, 2027. The Company received net proceeds of $492.1 million after deducting fees of $7.9 million, which are being amortized as deferred financing costs over the life of the 2027 Senior Notes. As discussed above, the net proceeds were used to fund the tender offer and redemption of all of the Company's 2023 Senior Notes and a portion of its 2022 Senior Notes.

Senior Convertible Notes

On August 12, 2016, the Company issued $172.5 million in aggregate principal amount of 1.50% Senior Convertible Notes due July 1, 2021, unless earlier converted. The Senior Convertible Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. The Company received net proceeds of $166.6 million after deducting fees of $5.9 million, of which a portion is being amortized over the life of the Senior Convertible Notes.

Holders may convert their Senior Convertible Notes at their option at any time prior to January 1, 2021, only under the following circumstances: (1) during any calendar quarter (and only during such calendar quarter) commencing after the calendar quarter ending on September 30, 2016, if the last reported sale price of the Company's common stock for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (2) during the five business day period after any five consecutive trading day period (the "measurement period") in which the trading price (as defined in the indenture) per $1,000 principal amount of Notes for each trading day of the measurement period was less than 98% of the product of the last reported sale price of the Company's common stock and the conversion rate on each such trading day; or (3) upon the occurrence of specified corporate events. On or after January 1, 2021, until the maturity date, holders may convert their Senior Convertible Notes at any time. The Company may not redeem the Senior Convertible Notes prior to the maturity date. Upon conversion, the Senior Convertible Notes may be settled, at the Company's election, in shares of the Company's common stock, cash, or a combination of cash and common stock. Holders may convert their notes based on a conversion rate of 24.6914 shares of the Company's common stock per $1,000 principal amount of the Senior Convertible Notes, which is equal to an initial conversion price of approximately $40.50 per share, subject to adjustment.

The Company has initially elected a net-settlement method to satisfy its conversion obligation, which would result in the Company settling the principal amount in cash with any excess conversion in shares of the Company's common stock. The Senior Convertible Notes were not convertible at the option of holders as of December 31, 2019, or through the filing of this report. Notwithstanding the inability to convert, the if-converted value of the Senior Convertible Notes as of December 31, 2019, did not exceed the principal amount.

Upon the issuance of the Senior Convertible Notes, the Company recorded $132.3 million as the initial carrying amount of the debt component, which approximated its fair value at issuance, and, was estimated by using an interest rate for nonconvertible debt with terms similar to the Senior Convertible Notes. The effective interest rate used was 7.25%. The $40.2 million excess of the principal amount of the Senior Convertible Notes over the fair value of the debt component was recorded as a debt discount and a corresponding increase in additional paid-in capital. The Company incurred transaction costs of $5.9 million relating to the issuance of the Senior Convertible Notes, which were allocated between the debt and equity components in proportion to their determined fair value amounts. The debt discount and debt-related issuance costs are amortized to the principal value of the Senior Convertible Notes as interest expense through the maturity date of July 1, 2021. Interest expense recognized on the Senior Convertible Notes related to the stated interest rate and amortization of the debt discount totaled $11.0 million, $10.5 million, and $9.9 million for the years ended December 31, 2019, 2018, and 2017, respectively.

The Senior Convertible Notes, net of unamortized discount and deferred financing costs line on the accompanying balance sheets consisted of the following as of December 31, 2019 and 2018:

	As of December 31,	
	2019	2018
	(in thousands)	
Principal amount of Senior Convertible Notes	$ 172,500	$ 172,500
Unamortized debt discount	(13,861)	(22,313)
Unamortized deferred financing costs	(1,376)	(2,293)
Senior Convertible Notes, net of unamortized discount and deferred financing costs	$ 157,263	$ 147,894

As of both December 31, 2019 and 2018, the net carrying amount of the equity component of the Senior Convertible Notes recorded in additional paid-in capital on the accompanying balance sheets was $33.6 million. There have been no changes to this amount since issuance.

If the Company undergoes a fundamental change, as defined by the governing indenture, holders of the Senior Convertible Notes may require the Company to repurchase for cash all or any portion of their notes at a fundamental change repurchase price equal to 100% of the principal amount of the Senior Convertible Notes to be repurchased, plus accrued and unpaid interest. The indenture governing the Senior Convertible Notes contains customary events of default with respect to the Senior Convertible Notes, including that upon certain events of default, the trustee by notice to the Company, or the holders of at least 25% in principal amount of the outstanding Senior Convertible Notes by notice to the Company, may declare 100% of the principal and accrued and unpaid interest, if any, due and payable immediately. In case of certain events of bankruptcy, insolvency or reorganization involving the Company or a significant subsidiary, 100% of the principal and accrued and unpaid interest on the Senior Convertible Notes will automatically become due and payable.

The Company is subject to certain covenants under the indenture governing the Senior Convertible Notes and was in compliance with all covenants as of December 31, 2019, and through the filing of this report.

Capped Call Transactions

In connection with the issuance of the Senior Convertible Notes, the Company entered into capped call transactions with affiliates of the underwriters of such issuance. The aggregate cost of the capped call transactions was approximately $24.2 million. The capped call transactions are generally expected to reduce the potential dilution upon conversion of the Senior Convertible Notes and/or partially offset any cash payments the Company is required to make in excess of the principal amount of converted Senior Convertible Notes in the event that the market price per share of the Company’s common stock is greater than the strike price of the capped call transactions, which initially corresponds to the approximate $40.50 per share conversion price of the Senior Convertible Notes. The cap price of the capped call transactions is initially $60.00 per share. If the market price per share exceeds the cap price of the capped call transactions, there could be dilution or there would not be an offset of such potential cash payments. The Company classified the costs associated with the capped call transactions as equity instruments with no recurring fair value measurement recorded.

Capitalized Interest

Capitalized interest costs for the Company for the years ended December 31, 2019, 2018, and 2017, totaled $18.5 million, $20.6 million, and $12.6 million, respectively. Capitalized interest costs are included in total costs incurred. Please refer to *Costs Incurred in Oil and Gas Producing Activities* in *Overview of the Company* in Part II, Item 7, and *Supplemental Oil and Gas Information (unaudited)* in Part II, Item 8 of this report.

Note 6 – Commitments and Contingencies

Commitments

The Company has entered into various agreements, which include drilling rig and completion service contracts of $34.1 million, gathering, processing, transportation throughput, and delivery commitments of $218.5 million, office leases, including maintenance, of $28.3 million, fixed price contracts to purchase electricity of $53.2 million, and other miscellaneous contracts and leases of $15.5 million. The annual minimum payments for the next five years and total minimum payments thereafter are presented below:

Years Ending December 31,	Amount (in thousands)
2020	$ 102,550
2021	94,494
2022	73,826
2023	41,661
2024	12,349
Thereafter	24,697
Total	$ 349,577

Drilling Rig and Completion Service Contracts. The Company has several drilling rig and completion service contracts in place to facilitate its drilling and completion plans. As of December 31, 2019, the Company's drilling rig and completion service contract commitments totaled $34.1 million, included in the table above. If all of these contracts were terminated as of December 31, 2019, the Company would avoid a portion of the contractual service commitments; however, the Company would be required to pay $26.3 million in early termination fees. Excluded from these amounts are variable commitments and potential penalties determined by the number of completion crews the Company has in operation in a particular area under a completion service arrangement. As of December 31, 2019, potential penalties under this completion service agreement, which expires on December 31, 2023, range from zero to a maximum of $13.4 million.

Pipeline Transportation Commitments. The Company has gathering, processing, transportation throughput, and delivery commitments with various third-parties that require delivery of a minimum amount of oil, gas, and produced water. As of December 31, 2019, the Company has commitments to deliver a minimum of 24 MMBbl of oil and 424 Bcf of gas through 2023, and 18 MMBbl of produced water through 2027. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments under certain agreements. As of December 31, 2019, if the Company fails to deliver any product, as applicable, the aggregate undiscounted deficiency payments total approximately $218.5 million. This amount does not include deficiency payment estimates associated with approximately 16.5 MMBbl of future oil delivery commitments where the Company cannot predict with accuracy the amount and timing of these payments, as such payments are dependent upon the price of oil in effect at the time of settlement. Under certain of the Company's commitments, if the Company is unable to deliver the minimum quantity from its production, it may deliver production acquired from third-parties to satisfy its minimum volume commitments.

Office Leases. The Company leases office space under various operating leases with terms extending as far as 2026. Rent expense for the years ended December 31, 2019, 2018, and 2017, was $5.5 million, $4.5 million, and $4.8 million, respectively.

Electrical Power Purchase Contracts. During the second quarter of 2019, the Company entered into a fixed price contract for the purchase of electrical power that increased the purchase commitment under an existing agreement. As of December 31, 2019, the Company had a commitment to purchase electrical power through 2027 with a total remaining obligation of $53.2 million.

Delivery and Purchase Commitments. During the second quarter of 2019, the Company executed an amendment to its existing sand sourcing agreement that created certain commitments and potential penalties that vary based on the amount of sand the Company uses in well completions occurring in a particular area. This amended sand sourcing agreement expires on December 31, 2023. As of December 31, 2019, potential penalties under this sand sourcing agreement range from zero to a maximum of $10.0 million.

Drilling and Completion Commitments. The Company has an agreement in place that includes minimum drilling and completion requirements on certain leases. If these minimum requirements are not satisfied by March 31, 2020, the Company would be required to make a liquidated damage payment based on the difference between actual development progress and the minimum development requirements. As of December 31, 2019, the Company did not expect to meet certain minimum development requirements.

In the fourth quarter of 2019, the Company recognized one-time charges associated with expected payments to lessors related to drilling and completion obligations and early termination fees for drilling rigs totaling $18.2 million. These amounts are included in the other operating expense line item on the accompanying statements of operations.

Contingencies

The Company is subject to litigation and claims arising in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the anticipated results of any pending litigation and claims are not expected to have a material effect on the results of operations, the financial position, or the cash flows of the Company.

Note 7 – Compensation Plans

Equity Incentive Compensation Plan

There are several components to the Company's Equity Incentive Compensation Plan ("Equity Plan") that are described in this section. Various types of equity awards have been granted by the Company in different periods.

As of December 31, 2019, approximately 4.4 million shares of common stock were available for grant under the Equity Plan. The issuance of a direct share benefit, such as a share of common stock, a stock option, a restricted share, an RSU, or a PSU, counts as one share against the number of shares available to be granted under the Equity Plan. Each PSU has the potential to count as two shares against the number of shares available to be granted under the Equity Plan based on the final performance multiplier.

Performance Share Units

The Company grants PSUs to eligible employees as part of its Equity Plan. The number of shares of the Company's common stock issued to settle PSUs ranges from zero to two times the number of PSUs awarded and is determined based on certain performance criteria over a three-year performance period. PSUs generally vest on the third anniversary of the date of the grant or upon other triggering events as set forth in the Equity Plan. Employees who are retirement eligible at the time a PSU award was granted, vest in each portion of that award equally in six-month increments over a three-year period beginning at grant date. Retirement eligible employees must stay with the Company through the entire six-month vesting period to receive that increment of vesting and any non-vested portions of a PSU award will be forfeited when the employee leaves the Company.

The fair value of PSUs is measured at the grant date with a stochastic Monte Carlo simulation using geometric Brownian motion ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSUs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the three-year performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the path the stock price may take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company's expected volatility, dividend yield, and risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with a three-year vesting period, as well as the volatilities and dividend yields for each of the Company's peers.

For PSUs granted in 2017, which the Company has determined to be equity awards, the settlement criteria include a combination of the Company's Total Shareholder Return ("TSR") on an absolute basis, and the Company's TSR relative to the TSR of certain peer companies over the associated three-year performance period. The fair value of the PSUs granted in 2017 was measured on the grant date using the GBM Model. As these awards depend entirely on market-based settlement criteria, the associated compensation expense is recognized on a straight-line basis within general and administrative expense and exploration expense over the vesting period of the awards.

For PSUs granted in 2018 and 2019, the settlement criteria include a combination of the Company's TSR relative to the TSR of certain peer companies and the Company's cash return on total capital invested ("CRTCI") relative to the CRTCI of certain peer companies over the associated three-year performance period. In addition to these performance measures, the award agreements for these grants also stipulate that if the Company's absolute TSR is negative over the three-year performance period, the maximum number of shares of common stock that can be issued to settle outstanding PSUs is capped at one times the number of PSUs granted on the award date, regardless of the Company's TSR and CRTCI performance relative to its peer group. The fair value of the PSUs granted in 2018 and 2019 was measured on the applicable grant dates using the GBM Model, with the assumption that the associated CRTCI performance condition will be met at the target amount at the end of the respective performance periods. Compensation expense for PSUs granted in 2018 and 2019 is recognized within general and administrative expense and exploration expense over the vesting periods of the respective awards. As these awards depend on a combination of performance-based settlement criteria and market-based settlement criteria, compensation expense may be adjusted in future periods as the number of units expected to vest increases or decreases based on the Company's expected CRTCI performance relative to the applicable peer companies.

The Company records compensation expense associated with the issuance of PSUs based on the fair value of the awards as of the date of grant. Total compensation expense recorded for PSUs was $10.9 million, $10.3 million, and $9.7 million for the years ended December 31, 2019, 2018, and 2017, respectively. As of December 31, 2019, there was $15.9 million of total unrecognized expense related to PSUs, which is being amortized through 2022.

A summary of the status and activity of non-vested PSUs is presented in the following table:

	For the Years Ended December 31,					
	2019		2018		2017	
	PSUs (1)	Weighted-Average Grant-Date Fair Value	PSUs (1)	Weighted-Average Grant-Date Fair Value	PSUs (1)	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	1,711,259	$ 20.68	1,533,491	$ 22.97	828,923	$ 43.25
Granted	793,125	$ 12.80	572,924	$ 24.45	977,731	$ 15.86
Vested	(346,021)	$ 26.32	(233,102)	$ 44.25	(94,338)	$ 85.85
Forfeited	(135,778)	$ 16.98	(162,054)	$ 21.79	(178,825)	$ 44.99
Non-vested at end of year	2,022,585	$ 16.87	1,711,259	$ 20.68	1,533,491	$ 22.97

(1) The number of awards assumes a multiplier of one. The final number of shares of common stock issued may vary depending on the three-year performance multiplier, which ranges from zero to two.

The fair value of the PSUs granted in 2019, 2018, and 2017 was $10.2 million, $14.0 million, and $15.5 million, respectively.

During the years ended December 31, 2019, 2018, and 2017, PSUs that were granted in 2016, 2015, and 2014, respectively did not satisfy the minimum performance requirements. This resulted in a multiplier of zero times and therefore no shares of common stock were issued upon settlement.

The total fair value of PSUs that vested during the years ended December 31, 2019, 2018, and 2017 was $9.1 million, $10.3 million, and $8.1 million, respectively.

Employee Restricted Stock Units

The Company grants RSUs to eligible persons as part of its Equity Plan. Each RSU represents a right to receive one share of the Company's common stock upon settlement of the award at the end of the specified vesting period. RSUs generally vest one-third of the total grant on each anniversary date of the grant over a three-year vesting period or upon other triggering events as set forth in the Equity Plan. Employees who are retirement eligible at the time an RSU award is granted, vest in each portion of that award equally in six-month increments over a three-year period beginning at grant date. Retirement eligible employees must stay with the Company through the entire six-month vesting period to receive that increment of vesting and any non-vested portions of an RSU award will be forfeited when the employee leaves the Company.

The Company records compensation expense associated with the issuance of RSUs based on the fair value of the awards as of the date of grant. The fair value of an RSU is equal to the closing price of the Company's common stock on the day of the grant. Compensation expense for RSUs is recognized within general and administrative expense and exploration expense over the vesting periods of the respective awards. Total compensation expense recorded for employee RSUs for the years ended December 31, 2019, 2018, and 2017, was $11.1 million, $10.8 million, and $10.3 million, respectively. As of December 31, 2019, there was $16.9 million of total unrecognized compensation expense related to non-vested RSU awards, which is being amortized through 2022.

A summary of the status and activity of non-vested RSUs granted to employees is presented in the following table:

	For the Years Ended December 31,					
	2019		2018		2017	
	RSUs	Weighted-Average Grant-Date Fair Value	RSUs	Weighted-Average Grant-Date Fair Value	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	1,243,163	$ 21.50	1,244,262	$ 20.25	604,116	$ 37.39
Granted	978,932	$ 12.36	583,552	$ 25.77	1,020,780	$ 16.64
Vested	(466,535)	$ 21.94	(407,529)	$ 24.30	(246,025)	$ 43.99
Forfeited	(223,429)	$ 18.16	(177,122)	$ 17.26	(134,609)	$ 26.38
Non-vested at end of year	1,532,131	$ 16.01	1,243,163	$ 21.50	1,244,262	$ 20.25

The fair value of RSUs granted to eligible employees in 2019, 2018, and 2017 was $12.1 million, $15.0 million, and $17.0 million, respectively.

A summary of the shares of common stock issued to settle employee RSUs is presented in the table below:

	For the Years Ended December 31,		
	2019	2018	2017
Shares of common stock issued to settle RSUs (1)	466,535	407,529	246,025
Less: shares of common stock withheld for income and payroll taxes	(132,136)	(115,784)	(74,747)
Net shares of common stock issued	334,399	291,745	171,278

(1) During the years ended December 31, 2019, 2018, and 2017, the Company issued shares of common stock to settle RSUs that related to awards granted in previous years. The Company and a majority of grant recipients mutually agreed to net share settle a portion of the awards to cover income and payroll tax withholdings in accordance with the Company's Equity Plan and individual award agreements.

The total fair value of employee RSUs that vested during the years ended December 31, 2019, 2018, and 2017 was $10.2 million, $9.9 million, and $10.8 million, respectively.

Director Shares

In 2019, 2018, and 2017, the Company issued 96,719, 63,741, and 71,573 shares, respectively, of its common stock to its non-employee directors under the Equity Plan. In 2017, the Company issued 8,794 RSUs to a non-employee director. For the years ended December 31, 2019, 2018, and 2017, the Company recorded $1.2 million, $1.7 million, and $1.6 million, respectively, of compensation expense related to director shares and RSUs issued.

All shares issued to non-employee directors fully vest on December 31 of the year granted. The RSUs issued to a non-employee director in 2017 fully vested on December 31, 2017, and will settle upon the earlier to occur of May 25, 2027, or the director resigning from the Board of Directors.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan ("ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation, without accruing in excess of $25,000 in value from purchases for each calendar year. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on either the first or last day of the purchase period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code (the "IRC"). The Company had approximately 1.3 million shares of its common stock available for issuance under the ESPP as of December 31, 2019. There were 314,868, 199,464, and 186,665 shares issued under the ESPP in 2019, 2018, and 2017, respectively. Total proceeds to the Company for the issuance of these shares were $3.2 million for each of the years ended December 31, 2019, and 2018, respectively, and $2.6 million for the year ended December 31, 2017.

The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model. Expected volatility is calculated based on the Company's historical daily common stock price, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with a six-month vesting period.

The fair value of ESPP shares issued during the periods reported were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,		
	2019	2018	2017
Risk free interest rate	2.3%	1.8%	0.9%
Dividend yield	0.7%	0.4%	0.5%
Volatility factor of the expected market price of the Company’s common stock	56.6%	55.9%	62.5%
Expected life (in years)	0.5	0.5	0.5

The Company expensed $1.1 million for each of the years ended December 31, 2019, and 2018, respectively, and $1.0 million for the year ended December 31, 2017, based on the estimated fair value of the ESPP grants.

401(k) Plan

The Company has a defined contribution plan (the “401(k) Plan”) that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute a maximum of 60 percent of their base salaries up to the contribution limits established under the IRC. For employees hired before December 31, 2014, the Company matches 100 percent of each employee’s contribution in cash on a dollar for dollar basis, up to six percent of the employee’s base salary and performance bonus, and may make additional contributions at its discretion. The Company matches 150 percent of contributions made by employees hired after December 31, 2014, up to six percent of the employee’s base salary and performance bonus in lieu of pension plan benefits, and may make additional contributions at its discretion. Please refer to *Note 8 – Pension Benefits* for additional discussion of pension benefits. The Company’s matching contributions to the 401(k) Plan were $5.1 million, $4.9 million, and $4.5 million for the years ended December 31, 2019, 2018, and 2017, respectively.

Note 8 – Pension Benefits

The Company has a non-contributory defined benefit pension plan covering employees who meet age and service requirements and who began employment with the Company prior to January 1, 2016 (the “Qualified Pension Plan”). The Company also has a supplemental non-contributory pension plan covering certain management employees (the “Nonqualified Pension Plan” and together with the Qualified Pension Plan, the “Pension Plans”). The Company froze the Pension Plans to new participants, effective as of January 1, 2016. Employees participating in the Pension Plans prior to the plans being frozen will continue to earn benefits.

Obligations and Funded Status for the Pension Plans

The Company recognizes the funded status (i.e. the difference between the fair value of plan assets and the projected benefit obligation) of the Company’s Pension Plans in the accompanying balance sheets as either an asset or a liability and recognizes a corresponding adjustment within the other comprehensive income (loss), net of tax, line item in the accompanying statements of comprehensive income (loss). The projected benefit obligation is the actuarial present value of the benefits earned to date by plan participants based on employee service and compensation including the effect of assumed future salary increases. The accumulated benefit obligation uses the same factors as the projected benefit obligation, but excludes the effects of assumed future salary increases. The Company’s measurement date for plan assets and obligations is December 31.

	For the Years Ended December 31,	
	2019	**2018**
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$ 66,086	$ 71,937
Service cost	5,582	6,730
Interest cost	2,791	2,622
Actuarial (gain) loss	2,035	(7,155)
Benefits paid	(5,651)	(8,048)
Projected benefit obligation at end of year	70,843	66,086
Change in plan assets:		
Fair value of plan assets at beginning of year	30,100	30,978
Actual return (loss) on plan assets	3,985	(964)
Employer contribution	7,200	8,134
Benefits paid	(5,651)	(8,048)
Fair value of plan assets at end of year	35,634	30,100
Funded status at end of year	$ (35,209)	$ (35,986)

The Company’s underfunded status for the Pension Plans as of December 31, 2019, and 2018, was $35.2 million and $36.0 million, respectively, and is recognized in the accompanying balance sheets within the other noncurrent liabilities line item. There are no plan assets in the Nonqualified Pension Plan.

Accumulated Benefit Obligation in Excess of Plan Assets for the Pension Plans

	As of December 31,	
	2019	**2018**
	(in thousands)	
Projected benefit obligation	$ 70,843	$ 66,086
Accumulated benefit obligation	$ 60,877	$ 52,368
Less: fair value of plan assets	(35,634)	(30,100)
Underfunded accumulated benefit obligation	$ 25,243	$ 22,268

Pension expense is determined based upon the annual service cost of benefits (the actuarial cost of benefits earned during a period) and the interest cost on those liabilities, less the expected return on plan assets. The expected long-term rate of return on plan assets is applied to a calculated value of plan assets that recognizes changes in fair value over a five-year period. This practice is intended to reduce year-to-year volatility in pension expense, but it can have the effect of delaying recognition of differences between actual returns on assets and expected returns based on long-term rate of return assumptions. Amortization of the unrecognized net gain or loss resulting from actual experience different from that assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of net periodic benefit cost for the year. If, as of the beginning of the year, the unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation and the market-related value of plan assets, then the amortization is the excess divided by the average remaining service period of participating employees expected to receive benefits under the plan.

The pre-tax amounts not yet recognized in net periodic pension costs, but rather recognized in the accumulated other comprehensive loss line item within the accompanying balance sheets as of December 31, 2019, and 2018, were as follows:

	As of December 31,	
	2019	2018
	(in thousands)	
Unrecognized actuarial losses	$ 14,406	$ 15,741
Unrecognized prior service costs	31	48
Accumulated other comprehensive loss	$ 14,437	$ 15,789

The pension liability adjustments recognized in other comprehensive income (loss) during 2019, 2018, and 2017, were as follows:

	For the Years Ended December 31,		
	2019	2018	2017
		(in thousands)	
Net actuarial gain (loss)	$ 377	$ 4,329	$ (2,995)
Amortization of prior service cost	17	18	17
Amortization of net actuarial loss	958	1,327	1,297
Settlements	—	—	3,009
Total pension liability adjustment, pre-tax	1,352	5,674	1,328
Tax expense	(291)	(4,265)	(561)
Cumulative effect of accounting change (1)	—	2,969	—
Total pension liability adjustment, net	$ 1,061	$ 4,378	$ 767

(1) Please refer to *Recently Issued Accounting Standards* in *Note 1 – Summary of Significant Accounting Policies* and *Statements of Stockholders' Equity* for additional information.

Components of Net Periodic Benefit Cost for the Pension Plans

	For the Years Ended December 31,		
	2019	2018	2017
		(in thousands)	
Components of net periodic benefit cost:			
Service cost	$ 5,582	$ 6,730	$ 6,638
Interest cost	2,791	2,622	2,689
Expected return on plan assets that reduces periodic pension benefit cost	(1,574)	(1,862)	(2,244)
Amortization of prior service cost	17	18	17
Amortization of net actuarial loss	958	1,327	1,297
Settlements	—	—	3,009
Net periodic benefit cost	$ 7,774	$ 8,835	$ 11,406

Pension Plan Assumptions

The weighted-average assumptions used to measure the Company's projected benefit obligation are as follows:

	As of December 31,	
	2019	2018
Projected benefit obligation:		
Discount rate	3.6%	4.4%
Rate of compensation increase	4.5%	6.2%

The weighted-average assumptions used to measure the Company's net periodic benefit cost are as follows:

	For the Years Ended December 31,		
	2019	2018	2017
Net periodic benefit cost:			
Discount rate	4.4%	3.8%	4.2%
Expected return on plan assets [1]	5.0%	5.5%	6.5%
Rate of compensation increase	6.2%	6.2%	6.2%

(1) There is no assumed expected return on plan assets for the Nonqualified Pension Plan because there are no plan assets in the Nonqualified Pension Plan.

The Company's pension investment policy includes various guidelines and procedures designed to ensure that assets are prudently invested in a manner necessary to meet the future benefit obligation of the Pension Plans. The policy prohibits the direct investment of plan assets in the Company's securities. The Qualified Pension Plan's investment horizon is long-term and accordingly the target asset allocations encompass a strategic, long-term perspective of capital markets, expected risk and return behavior and perceived future economic conditions. The key investment principles of diversification, assessment of risk, and targeting the optimal expected returns for given levels of risk are applied.

The Qualified Pension Plan's investment portfolio contains a diversified blend of investments, which may reflect varying rates of return. The investments are further diversified within each asset classification. This portfolio diversification provides protection against a single security or class of securities having a disproportionate impact on aggregate investment performance. The actual asset allocations are reviewed and rebalanced on a periodic basis to maintain the target allocations.

The weighted-average asset allocation of the Qualified Pension Plan is as follows:

	Target	As of December 31,	
Asset Category	**2020**	**2019**	**2018**
Equity securities	35.0%	36.9%	31.8%
Fixed income securities	40.0%	38.1%	41.3%
Other securities	25.0%	25.0%	26.9%
Total	100.0%	100.0%	100.0%

There is no asset allocation of the Nonqualified Pension Plan since there are no plan assets in the plan. An expected return on plan assets of 5.0 percent, 5.5 percent, and 6.5 percent was used to calculate the Company's net periodic pension cost under the Qualified Pension Plan for the years ended December 31, 2019, 2018, and 2017 respectively. The expected long-term rate of return assumption of the Qualified Pension Plan is based upon the target asset allocation and is determined using forward-looking assumptions in the context of historical returns and volatilities for each asset class, as well as correlations among asset classes. The Company evaluates the expected rate of return on plan assets assumption on an annual basis.

Pension Plan Assets

The fair values of the Company's Qualified Pension Plan assets as of December 31, 2019, and 2018, utilizing the fair value hierarchy discussed in *Note 11 – Fair Value Measurements* are as follows:

	Actual Asset Allocation (1)	Total	Fair Value Measurements Using: Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
			(in thousands)		
As of December 31, 2019					
Equity securities:					
Domestic (2)	17.3%	$ 6,176	$ 4,130	$ 2,046	$ —
International (3)	19.6%	6,958	6,958	—	—
Total equity securities	36.9%	13,134	11,088	2,046	—
Fixed income securities:					
Core fixed income (4)	31.4%	11,199	11,199	—	—
Floating rate corporate loans (5)	6.7%	2,379	2,379	—	—
Total fixed income securities	38.1%	13,578	13,578	—	—
Other securities:					
Real estate (6)	5.4%	1,929	—	—	1,929
Collective investment trusts (7)	3.3%	1,168	—	1,168	—
Hedge fund (8)	16.3%	5,825	2,006	—	3,819
Total other securities	25.0%	8,922	2,006	1,168	5,748
Total investments	100.0%	$ 35,634	$ 26,672	$ 3,214	$ 5,748
As of December 31, 2018					
Equity securities:					
Domestic (2)	15.4%	$ 4,639	$ 3,197	$ 1,442	$ —
International (3)	16.4%	4,941	3,642	1,299	—
Total equity securities	31.8%	9,580	6,839	2,741	—
Fixed income securities:					
Core fixed income (4)	34.4%	10,342	10,342	—	—
Floating rate corporate loans (5)	6.9%	2,078	2,078	—	—
Total fixed income securities	41.3%	12,420	12,420	—	—
Other securities:					
Real estate (6)	6.0%	1,820	—	—	1,820
Collective investment trusts (7)	3.1%	934	—	934	—
Hedge fund (8)	17.8%	5,346	—	1,659	3,687
Total other securities	26.9%	8,100	—	2,593	5,507
Total investments	100.0%	$ 30,100	$ 19,259	$ 5,334	$ 5,507

(1) Percentages may not calculate due to rounding.

(2) Level 1 equity securities consist of United States large and small capitalization companies, which are actively traded securities that can be sold upon demand. Level 2 equity securities are investments in a collective investment fund that is valued at net asset value based on the value of the underlying investments and total units outstanding on a daily basis. The objective of these funds is to approximate the S&P 500 by investing in one or more collective investment funds.

(3) International equity securities consists of a well-diversified portfolio of holdings of mostly large issuers organized in developed countries with liquid markets, commingled with investments in equity securities of issuers located in emerging markets and believed to have strong sustainable financial productivity at attractive valuations.

(4) The objective of core fixed income funds is to achieve value added from sector or issue selection by constructing a portfolio to approximate the investment results of the Barclay's Capital Aggregate Bond Index with a modest amount of variability in duration around the index.

(5) Investments consist of floating rate bank loans. The interest rates on these loans are typically reset on a periodic basis to account for changes in the level of interest rates.

(6) The investment objective of direct real estate is to provide current income with the potential for long-term capital appreciation. Ownership in real estate entails a long-term time horizon, periodic valuations, and potentially low liquidity.

(7) Collective investment trusts invest in short-term investments and are valued at the net asset value of the collective investment trust. The net asset value, as provided by the trustee, is used as a practical expedient to estimate fair value. The net asset value is based on the fair value of the underlying investments held by the fund less its liabilities.

(8) The hedge fund portfolio includes investments in actively traded global mutual funds that focus on alternative investments and a hedge fund of funds that invests both long and short using a variety of investment strategies.

Included below is a summary of the changes in Level 3 plan assets (in thousands):

Balance at January 1, 2018	$	5,209
Purchases		—
Realized gain on assets		191
Unrealized gain on assets		152
Disposition		(45)
Balance at December 31, 2018	$	5,507
Purchases		—
Realized gain on assets		190
Unrealized gain on assets		51
Disposition		—
Balance at December 31, 2019	$	5,748

Contributions

The Company contributed $7.2 million, $8.1 million, and $7.0 million to the Pension Plans for the years ended December 31, 2019, 2018, and 2017, respectively. The Company expects to make a $5.6 million contribution to the Pension Plans in 2020.

Benefit Payments

The Pension Plans made actual benefit payments of $5.7 million, $8.0 million, and $10.8 million in the years ended December 31, 2019, 2018, and 2017, respectively. Expected benefit payments over the next 10 years are as follows:

Years Ending December 31,	(in thousands)	
2020	$	7,609
2021	$	3,914
2022	$	4,022
2023	$	6,308
2024	$	4,939
2025 through 2029	$	25,065

Note 9 - Earnings Per Share

Basic net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average number of common shares outstanding for the respective period. Diluted net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the diluted weighted-average number of common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist primarily of non-vested RSUs, contingent PSUs, and shares into which the Senior Convertible Notes are convertible, which are measured using the treasury stock method.

PSUs represent the right to receive, upon settlement of the PSUs after the completion of the three-year performance period, a number of shares of the Company's common stock that may range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period applicable to such PSUs. For additional discussion on PSUs, please refer to *Note 7 – Compensation Plans* under the heading *Performance Share Units*.

On August 12, 2016, the Company issued $172.5 million in aggregate principal amount of Senior Convertible Notes due 2021. Upon conversion, the Senior Convertible Notes may be settled, at the Company's election, in shares of the Company's common stock, cash, or a combination of cash and common stock. The Company has initially elected a net-settlement method to satisfy its conversion obligation, which would result in the Company settling the principal amount of the Senior Convertible Notes in cash and the excess conversion value in shares. However, the Company has not made an irrevocable election and thereby reserves the right to settle the Senior Convertible Notes in any manner allowed under the indenture as business circumstances warrant. Shares of the Company's common stock traded at an average closing price below the $40.50 conversion price for the years ended December 31, 2019, 2018, and 2017, therefore, the Senior Convertible Notes had no dilutive impact. In connection with the offering of the Senior Convertible Notes, the Company entered into capped call transactions with affiliates of the underwriters that would effectively prevent dilution upon settlement up to the $60.00 cap price. The capped call transactions will always be anti-dilutive and therefore will never be reflected in diluted net income or loss per share. Please refer to *Note 5 – Long-Term Debt* for additional discussion.

When the Company recognizes a net loss from continuing operations, as was the case for the years ended December 31, 2019, and 2017, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted net loss per common share.

The following table details the weighted-average anti-dilutive securities for the years presented:

	For the Years Ended December 31,		
	2019	2018	2017
	(in thousands)		
Anti-dilutive	684	—	264

The following table sets forth the calculations of basic and diluted net income (loss) per common share:

	For the Years Ended December 31,		
	2019	2018	2017
	(in thousands, except per share data)		
Net income (loss)	$ (187,001)	$ 508,407	$ (160,843)
Basic weighted-average common shares outstanding	112,544	111,912	111,428
Dilutive effect of non-vested RSUs and contingent PSUs	—	1,590	—
Diluted weighted-average common shares outstanding	112,544	113,502	111,428
Basic net income (loss) per common share	$ (1.66)	$ 4.54	$ (1.44)
Diluted net income (loss) per common share	$ (1.66)	$ 4.48	$ (1.44)

Note 10 – Derivative Financial Instruments

Summary of Oil, Gas, and NGL Derivative Contracts in Place

The Company has entered into various commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. As of December 31, 2019, all derivative counterparties were members of the Company's Credit Agreement lender group and all contracts were entered into for other-than-trading purposes. The Company's commodity derivative contracts consist of swap and collar arrangements for oil and gas production, and swap arrangements for NGL production. In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference. For collar arrangements, the Company receives the difference between an agreed upon index price and the floor price if the index price is below the floor price. The Company pays the difference between the agreed upon ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

The Company has also entered into fixed price oil basis swaps in order to mitigate exposure to adverse pricing differentials between certain industry benchmark prices and the actual physical pricing points where the Company's production volumes are sold. Currently, the Company has basis swap contracts with fixed price differentials between NYMEX WTI and WTI Midland for a portion of its Midland Basin production with sales contracts that settle at WTI Midland prices. The Company also has basis swaps with fixed price differentials between NYMEX WTI and Intercontinental Exchange Brent Crude ("ICE Brent") for a portion of its Midland Basin oil production with sales contracts that settle at ICE Brent prices.

As of December 31, 2019, the Company had commodity derivative contracts outstanding through the fourth quarter of 2022, as summarized in the tables below.

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(MBbl)	(per Bbl)
First quarter 2020	2,486	$ 59.65
Second quarter 2020	2,838	$ 58.81
Third quarter 2020	3,361	$ 56.43
Fourth quarter 2020	3,937	$ 56.94
2021	667	$ 56.00
Total	13,289	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MBbl)	(per Bbl)	(per Bbl)
First quarter 2020	2,267	$ 55.00	$ 63.91
Second quarter 2020	1,881	$ 55.00	$ 62.17
Third quarter 2020	1,252	$ 55.00	$ 62.90
Fourth quarter 2020	610	$ 55.00	$ 61.90
2021	329	$ 55.00	$ 56.70
Total	6,339		

Oil Basis Swaps

Contract Period	WTI Midland-NYMEX WTI Volumes	Weighted-Average Contract Price [(1)]	NYMEX WTI-ICE Brent Volumes	Weighted-Average Contract Price [(2)]
	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)
First quarter 2020	4,193	$ (0.68)	—	$ —
Second quarter 2020	3,495	$ (0.68)	910	$ (8.06)
Third quarter 2020	3,325	$ (0.74)	920	$ (8.01)
Fourth quarter 2020	3,261	$ (0.73)	920	$ (8.01)
2021	5,954	$ 0.59	3,650	$ (7.86)
2022	—	$ —	3,650	$ (7.78)
Total	20,228		10,050	

(1) Represents the price differential between WTI Midland (Midland, Texas) and NYMEX WTI (Cushing, Oklahoma).
(2) Represents the price differential between NYMEX WTI (Cushing, Oklahoma) and ICE Brent (North Sea).

Gas Swaps

Contract Period	IF HSC Volumes	Weighted-Average Contract Price	WAHA Volumes	Weighted-Average Contract Price
	(BBtu)	(per MMBtu)	(BBtu)	(per MMBtu)
First quarter 2020	9,123	$ 2.98	3,099	$ 1.93
Second quarter 2020	4,160	$ 2.20	3,196	$ 0.56
Third quarter 2020	4,493	$ 2.41	3,268	$ 1.03
Fourth quarter 2020	3,722	$ 2.36	3,419	$ 1.17
2021	—	$ —	4,224	$ 1.51
Total [(1)]	21,498		17,206	

(1) The Company has natural gas swaps in place that settle against Inside FERC Houston Ship Channel (“IF HSC”), Inside FERC West Texas (“IF WAHA”), and Platt’s Gas Daily West Texas (“GD WAHA”). As of December 31, 2019, WAHA volumes were comprised of 92 percent IF WAHA and eight percent GD WAHA.

NGL Swaps

Contract Period	OPIS Ethane Purity Mont Belvieu		OPIS Propane Mont Belvieu Non-TET	
	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price
	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)
First quarter 2020	447	$ 11.53	382	$ 22.64
Second quarter 2020	264	$ 11.13	382	$ 22.34
Third quarter 2020	—	$ —	409	$ 22.33
Fourth quarter 2020	—	$ —	466	$ 22.29
Total	711		1,639	

Commodity Derivative Contracts Entered Into Subsequent to December 31, 2019

Subsequent to December 31, 2019, the Company entered into the following commodity derivative contracts:

- fixed price NYMEX WTI oil swap contracts for the fourth quarter of 2020 through January 2021 for a total of 0.6 MMBbl of oil production at a weighted-average contract price of $57.82 per Bbl; and
- fixed price WTI Midland-NYMEX WTI oil basis swap contracts for the second quarter of 2020 through the fourth quarter of 2022 for a total of 16.3 MMBbl of oil production at a weighted-average contract price of $1.14 per Bbl.

Derivative Assets and Liabilities Fair Value

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities, with the exception of derivative instruments that meet the "normal purchase normal sale" exclusion. The Company does not designate its derivative commodity contracts as hedging instruments. The fair value of the commodity derivative contracts at December 31, 2019, and 2018, was a net asset of $21.5 million and $158.3 million, respectively.

The following table details the fair value of commodity derivative contracts recorded in the accompanying balance sheets, by category:

	As of December 31, 2019	As of December 31, 2018
	(in thousands)	
Derivative assets:		
Current assets	$ 55,184	$ 175,130
Noncurrent assets	20,624	58,499
Total derivative assets	$ 75,808	$ 233,629
Derivative liabilities:		
Current liabilities	$ 50,846	$ 62,853
Noncurrent liabilities	3,444	12,496
Total derivative liabilities	$ 54,290	$ 75,349

Offsetting of Derivative Assets and Liabilities

As of December 31, 2019, and 2018, all derivative instruments held by the Company were subject to master netting arrangements with various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that settle on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company's commodity derivative contracts:

	Derivative Assets		Derivative Liabilities	
	As of December 31,		As of December 31,	
	2019	2018	2019	2018
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$ 75,808	$ 233,629	$ (54,290)	$ (75,349)
Amounts not offset in the accompanying balance sheets	(35,075)	(56,041)	35,075	56,041
Net amounts	$ 40,733	$ 177,588	$ (19,215)	$ (19,308)

The Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring such amounts in accumulated other comprehensive income (loss). The Company had no derivatives designated as hedging instruments for the years ended December 31, 2019, 2018, and 2017. Please refer to *Note 11 – Fair Value Measurements* for more information regarding the Company's derivative instruments, including its valuation techniques.

The following table summarizes the commodity components of the net derivative (gain) loss line item presented in the accompanying statements of operations:

	For the Years Ended December 31,		
	2019	2018	2017
	(in thousands)		
Derivative settlement (gain) loss:			
Oil contracts	$ 19,685	$ 68,860	$ 31,176
Gas contracts	(23,008)	13,029	(87,857)
NGL contracts	(35,899)	53,914	35,447
Total derivative settlement (gain) loss	$ (39,222)	$ 135,803	$ (21,234)
Net derivative (gain) loss:			
Oil contracts	$ 172,055	$ (192,002)	$ 71,502
Gas contracts	(41,205)	35,411	(76,315)
NGL contracts	(33,311)	(5,241)	31,227
Total net derivative (gain) loss	$ 97,539	$ (161,832)	$ 26,414

Credit Related Contingent Features

As of December 31, 2019, and through the filing of this report, all of the Company's derivative counterparties were members of the Company's Credit Agreement lender group. Under the Credit Agreement, the Company is required to provide mortgage liens on assets having a value equal to at least 85 percent of the total PV-9, as defined in the Credit Agreement, of the Company's proved oil and gas properties evaluated in the most recent reserve report. Collateral securing indebtedness under the Credit Agreement also secures the Company's derivative agreement obligations.

Note 11 – Fair Value Measurements

The Company follows fair value measurement accounting guidance for all assets and liabilities measured at fair value. This guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an 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. The fair value hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 – quoted prices in active markets for identical assets or liabilities
- Level 2 – quoted prices in active markets for similar assets or 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

Please refer to *Note 1 – Summary of Significant Accounting Policies* for additional information on the Company's policies for determining fair value for the categories discussed below.

The following table is a listing of the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they are classified within the fair value hierarchy as of December 31, 2019:

	Level 1	Level 2	Level 3
		(in thousands)	
Assets:			
Derivatives [(1)]	$ —	$ 75,808	$ —
Liabilities:			
Derivatives [(1)]	$ —	$ 54,290	$ —

[(1)] This represents a financial asset or liability that is measured at fair value on a recurring basis.

The following table is a listing of the Company's assets and liabilities that are measured at fair value in the accompanying balance sheets and where they are classified within the fair value hierarchy as of December 31, 2018:

	Level 1	Level 2	Level 3
		(in thousands)	
Assets:			
Derivatives [(1)]	$ —	$ 233,629	$ —
Liabilities:			
Derivatives [(1)]	$ —	$ 75,349	$ —

[(1)] This represents a financial asset or liability that is measured at fair value on a recurring basis.

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration forward commodity price curves, counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The commodity derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may require counterparties to post collateral if their ratings deteriorate. In some instances, the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any commodity derivative liability position. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company's credit rating, current credit facility margins, and any change in such margins since the last measurement date.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with authoritative accounting guidance and other marketplace participants, the Company recognizes that third-parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Refer to *Note 10 – Derivative Financial Instruments* for more information regarding the Company's derivative instruments.

Oil and Gas Properties

Proved oil and gas properties. Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that associated carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique to measure the fair value of proved properties through an application of discount rates and price forecasts representative of the current operating environment, as selected by the Company's management.

Unproved oil and gas properties. Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: remaining lease terms, future development plans, risk weighted potential resource recovery, estimated reserve values, and estimated acreage value based on price(s) received for similar, recent acreage transactions by the Company or other market participants.

There were no proved or unproved oil and gas properties recorded at fair value on the accompanying balance sheets as of December 31, 2019, or December 31, 2018.

The following table presents impairment of proved properties expense and abandonment and impairment of unproved properties expense recorded for the periods presented:

	For the Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Impairment of proved properties	$ —	$ —	$ 3.8
Abandonment and impairment of unproved properties	33.8	49.9	12.3
Impairment of oil and gas properties	$ 33.8	$ 49.9	$ 16.1

Abandonment and impairment of unproved properties expense recorded during the years ended December 31, 2019, 2018, and 2017 primarily related to actual and anticipated lease expirations, as well as actual and anticipated losses on acreage due to title defects, changes in development plans, and other inherent acreage risks.

Long-Term Debt

The following table reflects the fair value of the Company's unsecured senior note obligations measured using Level 1 inputs based on quoted secondary market trading prices. These notes were not presented at fair value on the accompanying balance sheets as of December 31, 2019, or 2018, as they were recorded at carrying value, net of any unamortized discounts and deferred financing costs. Please refer to *Note 5 – Long-Term Debt* for additional discussion.

	As of December 31,			
	2019		2018	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(in thousands)			
6.125% Senior Notes due 2022	$ 476,796	$ 481,564	$ 476,796	$ 452,336
5.0% Senior Notes due 2024	$ 500,000	$ 479,815	$ 500,000	$ 439,265
5.625% Senior Notes due 2025	$ 500,000	$ 475,835	$ 500,000	$ 436,460
6.75% Senior Notes due 2026	$ 500,000	$ 494,860	$ 500,000	$ 448,305
6.625% Senior Notes due 2027	$ 500,000	$ 493,750	$ 500,000	$ 442,500
1.50% Senior Convertible Notes due 2021	$ 172,500	$ 164,430	$ 172,500	$ 158,614

The carrying value of the Company's credit facility approximates its fair value, as the applicable interest rates are floating, based on prevailing market rates.

Note 12 - Leases

Effective January 1, 2019, the Company adopted Topic 842, which requires lessees to recognize operating and finance leases with terms greater than 12 months on the balance sheet. The Company adopted this standard using the modified retrospective method and elected to use the optional transition methodology whereby reporting periods prior to adoption continue to be presented in accordance with legacy accounting guidance. As of December 31, 2019, the Company did not have any agreements in place that were classified as finance leases under Topic 842. Arrangements classified as operating leases are included on the accompanying balance sheets within the other noncurrent assets, other current liabilities, and other noncurrent liabilities line items. For any agreement that contains both lease and non-lease components, such as a service arrangement that also includes an identifiable ROU asset, the Company's policy for all asset classes is to combine lease and non-lease components together and account for the arrangement as a single lease. Aside from the recognition of ROU assets and corresponding lease liabilities on the accompanying balance sheets, Topic 842 does not have a material impact on the timing or classification of costs incurred for those agreements considered to be leases.

As outlined in Topic 842, a ROU asset represents a lessee's right to use an underlying asset for the lease term, while the associated lease liability represents the lessee's obligations to make lease payments. At the commencement date, which is the date on which a lessor makes an underlying asset available for use by a lessee, a lease ROU asset and corresponding lease liability is recognized based on the present value of the future lease payments. The initial measurement of lease payments may also be adjusted for certain items, including options that are reasonably certain to be exercised, such as options to purchase the asset at the end of the lease term, or options to extend or early terminate the lease. Excluded from the initial measurement of a ROU asset and corresponding lease liability are certain variable lease payments, such as payments made that vary depending on actual usage or performance.

The Company evaluates a contractual arrangement at its inception to determine if it is a lease or contains an identifiable lease component as defined by Topic 842. When evaluating a contract to determine appropriate classification and recognition under Topic 842, significant judgment may be necessary to determine, among other criteria, if an embedded leasing arrangement exists, the length of the term, classification as either an operating or financing lease, which options are reasonably likely to be exercised, fair value of the underlying ROU asset or assets, upfront costs, and future lease payments that are included or excluded in the initial measurement of the ROU asset. Certain assumptions and judgments made by the Company when evaluating a contract that meets the definition of a lease under Topic 842 include:

- Discount Rate - Unless implicitly defined, the Company determines the present value of future lease payments using an estimated incremental borrowing rate based on a yield curve analysis that factors in certain assumptions, including the term of the lease and credit rating of the Company at lease inception.
- Lease Term - The Company evaluates each contract containing a lease arrangement at inception to determine the length of the lease term when recognizing a ROU asset and corresponding lease liability. When determining the lease term, options available to extend or early terminate the arrangement are evaluated and included when it is reasonably certain an option will be exercised. Because of the Company's intent to maintain financial and operational flexibility, there are no available options to extend that the Company is reasonably certain it will exercise. Additionally, based on expectations for those agreements with early termination options, there are no leases in which material early termination options are reasonably certain to be exercised by the Company.

Currently, the Company has operating leases for asset classes that include office space, office equipment, drilling rigs, midstream agreements, vehicles, and equipment rentals used in field operations. For those operating leases included on the accompanying balance sheets, which only includes leases with terms greater than 12 months at commencement, remaining lease terms range from less than one year to approximately six years. The weighted-average lease term remaining for these leases is approximately three years. Certain leases also contain optional extension periods that allow for terms to be extended for up to an additional 10 years. An early termination option also exists for certain leases, some of which allow for the Company to terminate a lease within one year. Exercising an early termination option may also result in an early termination penalty depending on the terms of the underlying agreement.

Subsequent to initial measurement, costs associated with the Company's operating leases are either expensed or capitalized depending on how the underlying ROU asset is utilized and in accordance with GAAP requirements. For example, costs associated with drilling rigs and completion crews that are considered ROU assets are typically capitalized as part of the development of the Company's oil and gas properties. Please refer to *Note 1 – Summary of Significant Accounting Policies* for additional information on its accounting policies for oil and gas development and producing activities. When calculating the Company's ROU asset and liability for a contractual arrangement that qualifies as an operating lease, the Company considers all of the necessary payments made or that are expected to be made upon commencement of the lease. Excluded from the initial measurement are certain variable lease payments, which for the Company's drilling rigs, completion crews, and midstream agreements, may be a significant component of the total lease costs.

For the year ended December 31, 2019, total costs related to operating leases, including short-term leases, and variable lease payments made for leases with initial lease terms greater than 12 months, were $442.9 million. This total does not reflect amounts that may be reimbursed by other third parties in the normal course of business, such as non-operating working interest owners.

Components of the Company's total lease cost, whether capitalized or expensed, for the year ended December 31, 2019, were as follows:

	For the Year Ended December 31, 2019	
Operating lease cost	$	35,570
Short-term lease cost [(1)]		301,373
Variable lease cost [(2)]		106,006
Total lease cost [(3)]	$	442,949

(1) Costs associated with short-term lease agreements relate primarily to operational activities where underlying lease terms are less than one year. This amount is significant as it includes drilling and completion activities and field equipment rentals, most of which are contracted for 12 months or less. It is expected that this amount will fluctuate primarily with the number of drilling rigs and completion crews the Company is operating under short-term agreements.

(2) Variable lease payments include additional payments made that were not included in the initial measurement of the ROU asset and corresponding liability for lease agreements with terms longer than 12 months. Variable lease payments relate to the actual volumes transported under certain midstream agreements, actual usage associated with drilling rigs, completion crews, and vehicles, and variable utility costs associated with the Company's leased office space. Fluctuations in variable lease payments are driven by actual volumes delivered and the number of drilling rigs and completion crews operating under long-term agreements.

(3) Lease costs are either expensed on the accompanying statements of operations or capitalized on the accompanying balance sheets depending on the nature and use of the underlying ROU asset.

Other information related to the Company's leases for the year ended December 31, 2019, was as follows:

	For the Year Ended December 31, 2019	
	(in thousands)	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	12,074
Investing cash flows from operating leases	$	24,129
Right-of-use assets obtained in exchange for new operating lease liabilities	$	25,360

Maturities for the Company's operating lease liabilities included on the accompanying balance sheets as of December 31, 2019, were as follows:

	As of December 31, 2019	
	(in thousands)	
2020	$	21,102
2021		12,600
2022		5,749
2023		3,602
2024		2,081
Thereafter		1,639
Total Lease payments	$	46,773
Less: Imputed interest [(1)]		(4,447)
Total	$	42,326

(1) The weighted-average discount rate used to determine the operating lease liability as of December 31, 2019 was 6.6 percent.

Amounts recorded on the accompanying balance sheets for operating leases as of December 31, 2019, were as follows:

		As of December 31, 2019
		(in thousands)
Other noncurrent assets	$	39,717
Other current liabilities	$	19,189
Other noncurrent liabilities	$	23,137

As of December 31, 2019, and through the filing of this report, the Company has no material lease arrangements which are scheduled to commence in the future.

Note 13 – Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following accruals:

	As of December 31,			
	2019		2018	
	(in thousands)			
Oil, gas, and NGL production revenue	$	146,308	$	107,230
Amounts due from joint interest owners		22,681		31,497
State severance tax refunds		4,069		4,415
Derivative settlements		6,868		9,475
Other		4,806		14,919
Total accounts receivable	$	184,732	$	167,536

Accounts payable and accrued expenses are comprised of the following accruals:

	As of December 31,			
	2019		2018	
	(in thousands)			
Drilling and lease operating cost accruals	$	96,925	$	139,711
Trade accounts payable		52,094		56,047
Revenue and severance tax payable		109,847		94,806
Property taxes		24,535		18,694
Compensation		41,540		31,486
Derivative settlements		5,851		1,287
Interest		44,175		40,840
Other		27,041		20,328
Total accounts payable and accrued expenses	$	402,008	$	403,199

Note 14 – Asset Retirement Obligations

Please refer to *Asset Retirement Obligations* in *Note 1 – Summary of Significant Accounting Policies* for a discussion of the initial and subsequent measurements of asset retirement obligation liabilities and the significant assumptions used in the estimates.

A reconciliation of the Company's total asset retirement obligation liability is as follows:

	As of December 31,	
	2019	2018
	(in thousands)	
Beginning asset retirement obligations	$ 94,194	$ 114,470
Liabilities incurred [(1)]	3,927	4,054
Liabilities settled [(2)]	(4,105)	(33,024)
Accretion expense	4,016	4,438
Revision to estimated cash flows	(11,186)	4,256
Ending asset retirement obligations [(3)]	$ 86,846	$ 94,194

(1) Reflects liabilities incurred through drilling activities and acquisitions of drilled wells.
(2) Reflects liabilities settled through plugging and abandonment activities and divestitures of properties.
(3) Balances as of December 31, 2019, and 2018, included $2.7 million and $2.3 million, respectively, related to the Company's current asset retirement obligation liability, which is recorded in the accounts payable and accrued expenses line item on the accompanying balance sheets.

Note 15 – Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2019, 2018, and 2017. The table does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same year:

	For the Years Ended December 31,		
	2019	2018	2017
		(in thousands)	
Beginning balance	$ 11,197	$ 49,446	$ 19,846
Additions to capitalized exploratory well costs pending the determination of proved reserves	11,925	11,197	49,446
Divestitures	—	(109)	—
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(11,197)	(49,337)	(19,846)
Capitalized exploratory well costs charged to expense	—	—	—
Ending balance	$ 11,925	$ 11,197	$ 49,446

As of December 31, 2019, there were no exploratory well costs that were capitalized for more than one year.

Supplemental Oil and Gas Information (unaudited)

Costs Incurred in Oil and Gas Producing Activities

Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Years Ended December 31,		
	2019	2018	2017
		(in thousands)	
Development costs [(1)]	$ 913,959	$ 1,147,574	$ 675,523
Exploration costs	114,957	184,930	271,502
Acquisitions			
Proved properties	(310)	1,312	1,602
Unproved properties [(2)]	11,633	55,688	91,420
Total, including asset retirement obligations [(3)(4)]	$ 1,040,239	$ 1,389,504	$ 1,040,047

(1) Includes facility costs of $28.3 million, $72.6 million, and $43.8 million for the years ended December 31, 2019, 2018, and 2017, respectively.
(2) Includes amounts related to leasing activity and acquiring surface rights outside of acquisitions of proved and unproved properties totaling $8.7 million, $23.4 million, and $12.8 million for the years ended December 31, 2019, 2018, and 2017, respectively.
(3) Includes amounts relating to estimated asset retirement obligations of $(9.9) million, $7.1 million, and $13.6 million for the years ended December 31, 2019, 2018, and 2017, respectively.
(4) Includes capitalized interest of $18.5 million, $20.6 million, and $12.6 million for the years ended December 31, 2019, 2018, and 2017, respectively.

Oil and Gas Reserve Quantities

The reserve estimates presented below were made in accordance with GAAP requirements for disclosures about oil and gas producing activities and SEC rules for oil and gas reporting of reserve estimation and disclosure.

Proved reserves are the estimated quantities of oil, gas, and NGLs 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is 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. All of the Company’s estimated proved reserves are located in the United States.

The table below presents a summary of changes in the Company's estimated proved reserves for each of the years in the three-year period ended December 31, 2019. The Company engaged Ryder Scott to audit internal engineering estimates for at least 80 percent of the Company's total calculated proved reserve PV-10 for each year presented. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

	For the Years Ended December 31,								
	2019 [1]			2018 [2]			2017 [3]		
	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)
Total proved reserves:									
Beginning of year	175.7	1,321.8	107.4	158.2	1,280.1	96.5	104.9	1,111.1	105.7
Revisions of previous estimate	(19.2)	(212.5)	(40.0)	(24.0)	(219.5)	(8.0)	1.0	63.8	4.9
Discoveries and extensions	5.4	28.8	2.9	9.3	20.3	0.5	11.5	21.9	—
Infill reserves in an existing proved field	41.8	190.2	11.8	80.4	391.5	29.0	79.0	347.4	22.9
Sales of reserves [4]	(0.2)	(0.7)	—	(29.6)	(48.1)	(2.7)	(25.3)	(143.8)	(26.7)
Purchases of minerals in place [4]	2.5	5.4	—	0.2	0.7	—	0.8	2.7	—
Production	(21.9)	(109.8)	(8.1)	(18.8)	(103.2)	(7.9)	(13.7)	(123.0)	(10.3)
End of year	184.1	1,223.2	74.0	175.7	1,321.8	107.4	158.2	1,280.1	96.5
Proved developed reserves:									
Beginning of year	68.2	699.1	60.1	58.6	642.9	49.0	48.5	609.1	58.6
End of year	85.0	712.1	43.4	68.2	699.1	60.1	58.6	642.9	49.0
Proved undeveloped reserves:									
Beginning of year	107.6	622.7	47.2	99.6	637.2	47.6	56.4	502.0	47.1
End of year	99.1	511.1	30.6	107.6	622.7	47.2	99.6	637.2	47.6

Note: Amounts may not calculate due to rounding.

(1) For the year ended December 31, 2019, the Company added 98.4 MMBOE from its drilling program and further development plan optimization. These additions were offset by net downward revisions of 94.7 MMBOE, which were primarily driven by declining commodity prices during 2019. Please refer to *Areas of Operation* in Part I, Items 1 and 2 of this report, and to *Oil and Gas Reserve Quantities* in *Critical Accounting Policies and Estimates* in Part II, Item 7 of this report for additional information.

(2) For the year ended December 31, 2018, the Company added 188.0 MMBOE from its drilling program and through development plan optimization. The Company divested 40.3 MMBOE during 2018, primarily as a result of the PRB Divestiture, Divide County Divestiture, and Halff East Divestiture. The Company also had net downward revisions of 68.8 MMBOE, which resulted primarily from changes in development plans in its Eagle Ford shale program.

(3) For the year ended December 31, 2017, the Company added 175.0 MMBOE from its drilling program. The Company divested 76.0 MMBOE during 2017, including 72.5 MMBOE related to its outside-operated Eagle Ford shale assets.

(4) Please refer to *Note 3 – Divestitures, Assets Held for Sale, and Acquisitions* for additional information.

Standardized Measure of Discounted Future Net Cash Flows

The Company computes a standardized measure of future net cash flows ("Standardized Measure") and changes therein relating to estimated proved reserves in accordance with authoritative accounting guidance. Future cash inflows and production and development costs are determined by applying prices and costs, including transportation, quality, and basis differentials, to the year end estimated future reserve quantities. Each property the Company operates is also charged with field-level overhead in the estimated reserve calculation. Estimated future income taxes are computed using the current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a 10 percent annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the estimated proved reserves in place at the end of the period using year end costs and assuming continuation of existing economic conditions, plus Company overhead incurred by the central administrative office attributable to operating activities.

The assumptions used to compute the Standardized Measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value amount. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the Standardized Measure computations since these reserve quantity estimates are the basis for the valuation process. The following prices as adjusted for transportation, quality, and basis differentials were used in the calculation of the Standardized Measure:

	For the Years Ended December 31,		
	2019	2018	2017
Oil (per Bbl)	$ 53.68	$ 57.76	$ 48.57
Gas (per Mcf)	$ 2.49	$ 3.49	$ 3.20
NGLs (per Bbl)	$ 18.88	$ 26.23	$ 23.33

The following summary sets forth the Company's future net cash flows relating to proved oil, gas, and NGL reserves based on the Standardized Measure.

	As of December 31,		
	2019	2018	2017
	(in thousands)		
Future cash inflows	$ 14,327,131	$ 17,579,432	$ 14,035,704
Future production costs	(4,579,119)	(5,386,264)	(5,594,226)
Future development costs	(2,108,859)	(2,679,488)	(2,638,459)
Future income taxes	(579,815)	(1,012,209)	(205,694)
Future net cash flows	7,059,338	8,501,471	5,597,325
10 percent annual discount	(2,955,340)	(3,847,088)	(2,573,183)
Standardized measure of discounted future net cash flows	$ 4,103,998	$ 4,654,383	$ 3,024,142

The principle sources of changes in the Standardized Measure were:

	For the Years Ended December 31,		
	2019	2018	2017
	(in thousands)		
Standardized Measure, beginning of year	$ 4,654,383	$ 3,024,142	$ 1,152,113
Sales of oil, gas, and NGLs produced, net of production costs	(1,085,041)	(1,148,991)	(745,877)
Net changes in prices and production costs	(1,539,042)	1,010,335	1,181,447
Extensions, discoveries and other including infill reserves in an existing proved field, net of related costs	887,254	2,218,475	1,638,734
Sales of reserves in place	(2,788)	(147,887)	(226,528)
Purchase of reserves in place	57,519	1,818	12,032
Previously estimated development costs incurred during the period	736,770	445,638	121,879
Changes in estimated future development costs	132,825	(34,871)	(116,609)
Revisions of previous quantity estimates	(398,409)	(611,168)	103,916
Accretion of discount	510,427	305,657	115,211
Net change in income taxes	191,040	(449,884)	(32,426)
Changes in timing and other	(40,940)	41,119	(179,750)
Standardized Measure, end of year	$ 4,103,998	$ 4,654,383	$ 3,024,142

Quarterly Financial Information (unaudited)

The Company's quarterly financial information for fiscal years 2019 and 2018 is as follows (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2019 (1)				
Total operating revenues and other income	$ 340,930	$ 407,172	$ 390,317	$ 451,686
Total operating expenses	526,239	303,005	290,840	539,989
Income (loss) from operations	$ (185,309)	$ 104,167	$ 99,477	$ (88,303)
Income (loss) before income taxes	$ (223,606)	$ 63,978	$ 58,345	$ (129,761)
Net income (loss)	$ (177,568)	$ 50,388	$ 42,234	$ (102,055)
Basic net income (loss) per common share	$ (1.58)	$ 0.45	$ 0.37	$ (0.90)
Diluted net income (loss) per common share	$ (1.58)	$ 0.45	$ 0.37	$ (0.90)
Dividends declared per common share	$ 0.05	$ —	$ 0.05	$ —
Year Ended December 31, 2018 (2)				
Total operating revenues and other income	$ 769,595	$ 443,916	$ 459,369	$ 394,192
Total operating expenses	310,527	387,768	568,013	(35,573)
Income (loss) from operations	$ 459,068	$ 56,148	$ (108,644)	$ 429,765
Income (loss) before income taxes	$ 416,392	$ 16,296	$ (172,671)	$ 391,760
Net income (loss)	$ 317,401	$ 17,197	$ (135,923)	$ 309,732
Basic net income (loss) per common share	$ 2.84	$ 0.15	$ (1.21)	$ 2.76
Diluted net income (loss) per common share	$ 2.81	$ 0.15	$ (1.21)	$ 2.73
Dividends declared per common share	$ 0.05	$ —	$ 0.05	$ —

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(1) Results of operations during 2019 were primarily impacted by the following:
- a net derivative loss of $177.1 million recorded in the first quarter of 2019,
- a net derivative gain of $79.7 million recorded in the second quarter of 2019,
- a net derivative gain of $100.9 million recorded in the third quarter of 2019, and
- a net derivative loss of $101.0 million recorded in the fourth quarter of 2019.

Please refer to *Note 10 – Derivative Financial Instruments* for greater detail.

(2) For the first quarter of 2018, the Company recorded an estimated $409.2 million net pre-tax gain on divestiture activity related to the PRB Divestiture, which was partially offset by a $24.1 million write-down on certain assets. During the second quarter of 2018, the Company recorded an estimated $15.7 million net pre-tax gain on divestiture activity related to the Divide County Divestiture and Halff East Divestiture (please refer to *Note 3 – Divestitures, Assets Held for Sale, and Acquisitions*). During the third quarter of 2018, the Company recorded a $26.7 million loss on the early extinguishment of its 2021 Senior Notes, 2023 Senior Notes, and a portion of its 2022 Senior Notes (please refer to *Note 5 – Long-Term Debt*). For the first, second, third, and fourth quarters of 2018, the Company recorded net derivative losses of $7.5 million, $63.7 million, $178.0 million, and a net derivative gain of $411.1 million. Please refer to *Note 10 – Derivative Financial Instruments* for greater detail.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the fourth quarter of 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting is 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. The Company's internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) 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

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that have a material effect on the financial statements.

Because of the inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. Even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of the changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework* (2013 framework).

Based on our assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2019.

The Company's independent registered public accounting firm has issued an attestation report on the Company's internal control over financial reporting. That report immediately follows this report.

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of SM Energy Company and subsidiaries

Opinion on Internal Control over Financial Reporting

We have audited SM Energy Company and subsidiaries' internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, SM Energy Company and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of 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 and our report dated February 20, 2020 expressed an unqualified opinion thereon.

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/ Ernst & Young LLP

Denver, Colorado
February 20, 2020

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information required by this Item concerning the Company's Directors, Executive Officers, and corporate governance is incorporated by reference to the information provided under the captions *"Proposal 1 - Election of Directors," "Information about Executive Officers,"* and *"Corporate Governance"* in the Company's definitive proxy statement for the 2020 annual meeting of stockholders to be filed within 120 days from December 31, 2019.

The information required by this Item concerning compliance with Section 16(a) of the Exchange Act is incorporated by reference to the information provided under the caption *"Section 16(a) Beneficial Ownership Reporting Compliance"* in the Company's definitive proxy statement for the 2020 annual meeting of stockholders to be filed within 120 days from December 31, 2019.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided under the captions *"Executive Compensation"* and *"Director Compensation"* in the Company's definitive proxy statement for the 2020 annual meeting of stockholders to be filed within 120 days from December 31, 2019.

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

The information required by this Item concerning security ownership of certain beneficial owners and management is incorporated by reference to the information provided under the caption *"Security Ownership of Certain Beneficial Owners and Management"* in the Company's definitive proxy statement for the 2020 annual meeting of stockholders to be filed within 120 days from December 31, 2019.

Securities Authorized for Issuance Under Equity Compensation Plans. The Company has equity compensation plans under which options and shares of the Company's common stock are authorized for grant or issuance as compensation to eligible employees, consultants, and members of the Board of Directors. The Company's stockholders have approved these plans. Please refer to *Note 7 – Compensation Plans* in Part II, Item 8 of this report for further information about the material terms of the Company's equity compensation plans. The following table is a summary of the shares of common stock authorized for issuance under equity compensation plans as of December 31, 2019:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
Equity Incentive Compensation Plan [1]			
Restricted stock units [2]	1,540,925	N/A	
Performance share units [2][3]	2,044,882	N/A	
Total for Equity Incentive Compensation Plan	3,585,807	$ —	4,385,709
Employee Stock Purchase Plan [4]	—	—	1,299,003
Equity compensation plans not approved by security holders	—	—	—
Total for all plans	3,585,807	$ —	5,684,712

(1) In May 2006, the stockholders approved the Equity Plan to authorize the issuance of restricted stock, restricted stock units, non-qualified stock options, incentive stock options, stock appreciation rights, performance shares, performance units, and stock-based awards to key employees, consultants, and members of the Board of Directors of the Company or any affiliate of the Company. The Company's Board of Directors approved amendments to the Equity Plan in 2009, 2010, 2013, 2016, and 2018 and each amended plan was approved by stockholders at the respective annual stockholders' meetings. The number of shares of the Company's common stock underlying awards granted in 2019, 2018, and 2017 under the Equity Plan were 1,868,776, 1,220,217, and 2,078,878, respectively.

(2) RSUs and PSUs do not have exercise prices associated with them, but rather a weighted-average per unit fair value, which is presented in order to provide additional information regarding the potential dilutive effect of the awards. The weighted-average grant date per unit fair value for the outstanding RSUs and PSUs was $16.04 and $16.89, respectively. Please refer to *Note 7 – Compensation Plans* in Part II, Item 8 of this report for additional discussion.

(3) The number of awards to be issued assumes a one multiplier. The final number of shares of the Company's common stock issued upon settlement may vary depending on the three-year multiplier determined at the end of the performance period under the Equity Plan, which ranges from zero to two.

(4) Under the ESPP, eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of their eligible compensation. The purchase price of the common stock is 85 percent of the lower of the fair market value of the common stock on the first or last day of the six-month offering period, and shares issued under the ESPP on or after December 31, 2011, have no minimum restriction period. The ESPP is intended to qualify under Section 423 of the IRC. The number of shares of the Company's common stock issued in 2019, 2018, and 2017 under the ESPP were 314,868, 199,464, and 186,665, respectively.

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

The information required by this Item is incorporated by reference to the information provided under the captions "*Certain Relationships and Related Transactions*" and "*Corporate Governance*" in the Company's definitive proxy statement for the 2020 annual meeting of stockholders to be filed within 120 days from December 31, 2019.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided under the captions "*Independent Registered Public Accounting Firm*" and "*Audit Committee Pre-approval Policy and Procedures*" in the Company's definitive proxy statement for the 2020 annual meeting of stockholders to be filed within 120 days from December 31, 2019.

PART IV

ITEM 15. EXHIBITS AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Consolidated Financial Statements and Financial Statement Schedules:

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statements and Notes thereto.

(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

Exhibit Number	Description
2.1	Membership Interest Purchase Agreement dated January 1, 2017 between SM Energy Company and Venado EF LLC (filed as Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, and incorporated herein by reference)
2.2	Second Amendment to Membership Interest Purchase Agreement dated March 4, 2017 between SM Energy and Venado EF L.P. (filed as Exhibit 2.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, and incorporated herein by reference)
2.3	Purchase and Sale Agreement dated January 8, 2018 by and between SM Energy Company and Converse Energy Acquisitions, LLC (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on January 11, 2018 and incorporated herein by reference)
3.1	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
3.2	Amended and Restated By-Laws of SM Energy Company, effective as of February 21, 2017 (filed as Exhibit 3.2 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2016, and incorporated herein by reference)
4.1	Indenture related to the 5.0% Senior Notes due 2024, dated May 20, 2013, by and between SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on May 20, 2013, and incorporated herein by reference)
4.2	Indenture related to the 6.125% Senior Notes due 2022, dated November 17, 2014, by and between SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on November 18, 2014, and incorporated herein by reference)
4.3	Indenture related to senior debt securities of SM Energy Company by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant's Registration Statement on Form S-3 filed on May 7, 2015 (Registration No. 333-203936) and incorporated herein by reference)
4.4	2025 Notes Supplemental Indenture (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on May 21, 2015, and incorporated herein by reference)
4.5	Base Indenture, dated as of May 21, 2015, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
4.6	Second Supplemental Indenture, dated August 12, 2016, by and between SM Energy Company and U.S. Bank, National Association, as trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
4.7	Third Supplemental Indenture, dated September 12, 2016 by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on September 12, 2016, and incorporated herein by reference)
4.8	Fourth Supplemental Indenture, dated as of August 20, 2018, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on August 20, 2018, and incorporated herein by reference)

4.9	Supplemental Indenture, dated as of August 20, 2018, by and between SM Energy Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.3 to the registrant's Current Report on Form 8-K filed on August 20, 2018, and incorporated herein by reference)
4.10†	SM Energy Company Equity Incentive Compensation Plan, amended and restated effective as of May 22, 2018 (filed as Annex A in the registrant's Definitive Proxy Statement on Schedule 14A, filed on April 12, 2018, and incorporated herein by reference)
4.11*	Description of Securities
10.1	Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.2	Deed of Trust to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.3†	Form of Non-Employee Director Restricted Stock Award Agreement as of May 27, 2010 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, and incorporated herein by reference)
10.4***	Gas Services Agreement effective as of July 1, 2010 between SM Energy Company and Eagle Ford Gathering LLC (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010, and incorporated herein by reference)
10.5††	Net Profits Interest Bonus Plan, As Amended by the Board of Directors on July 30, 2010 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.6†	Pension Plan for Employees of SM Energy Company as Amended and Restated as of January 1, 2010 (filed as Exhibit 10.30 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)
10.7+	SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan as Amended as of December 31, 2010 (filed as Exhibit 10.31 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)
10.8***	Gas Gathering Agreement dated May 31, 2011 between Regency Field Services LLC and SM Energy Company (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.9***	Gathering and Natural Gas Services Agreement effective as of April 1, 2011 between SM Energy Company and ETC Texas Pipeline, Ltd. (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.10***	Gas Processing Agreement effective as of April 1, 2011 between ETC Texas Pipeline, Ltd. and SM Energy Company (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.11†	Employee Stock Purchase Plan, As Amended and Restated as of June 10, 2011 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.12†	Amendment No. 1 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2011 (filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2011, and incorporated herein by reference)
10.13†	Amendment No. 2 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2012 (filed as Exhibit 10.42 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2011, and incorporated herein by reference)
10.14†	SM Energy Company Non-Qualified Deferred Compensation Plan as of March 10, 2014 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 24, 2014, and incorporated herein by reference)
10.15†	Cash Bonus Plan, As Amended and Restated as of February 1, 2014 (filed as Exhibit 10.41 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2013, and incorporated herein by reference)
10.16†	Section 162(m) Cash Bonus Plan, effective as of May 21, 2014 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 28, 2014, and incorporated herein by reference)
10.17*†	Summary of Compensation Arrangements for Non-Employee Directors
10.18	Sixth Amended and Restated Credit Agreement dated as of September 28, 2018, among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on October 4, 2018, and incorporated herein by reference)
10.19†	Change of Control Executive Severance Agreement (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on October 20, 2015, and incorporated herein by reference)

10.20†	Amendment No. 3 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2016 (filed as Exhibit 10.29 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2015, and incorporated herein by reference)
10.21***	Amendment to Amended and Restated Gas Gathering Agreement, effective as of September 1, 2015, by and between SM Energy Company and Regency Field Services LLC (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on September 15, 2015, and incorporated herein by reference)
10.22	Amendment to Amended and Restated Gas Gathering Agreement, effective as of February 1, 2016, by and between SM Energy Company and ETC Field Services LLC (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on February 22, 2016, and incorporated herein by reference)
10.23	Call Option Confirmation, dated August 8, 2016, by and between SM Energy Company and Wells Fargo Bank, National Association (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
10.24	Call Option Confirmation, dated August 8, 2016, by and between SM Energy Company and Bank of America, N.A. (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
10.25	Call Option Confirmation, dated August 8, 2016, by and between SM Energy Company and JPMorgan Chase Bank, National Association (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
10.26	Call Option Confirmation, dated August 10, 2016, by and between SM Energy Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
10.27	Call Option Confirmation, dated August 10, 2016, by and between SM Energy Company and Bank of America, N.A. (filed as Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
10.28	Call Option Confirmation, dated August 10, 2016, by and between SM Energy Company and JPMorgan Chase Bank, National Association (filed as Exhibit 10.6 to the registrant's Current Report on Form 8-K filed on August 12, 2016, and incorporated herein by reference)
10.29†	SM Energy Company Employee Stock Purchase Plan, amended and restated effective as of April 6, 2017 (filed as Annex A in the registrant's Definitive Proxy Statement on Schedule 14A, filed on April 13, 2017, and incorporated herein by reference)
10.30†	Performance Share Unit Award Agreement as of July 1, 2018 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, and incorporated herein by reference)
10.31	First Amendment to Sixth Amended and Restated Credit Agreement, dated April 18, 2019 among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 18, 2019, and incorporated herein by reference)
10.32†	Performance Share Unit Award Agreement as of July 1, 2019 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2019, and incorporated herein by reference)
10.33	Second Amendment to Sixth Amended and Restated Credit Agreement, dated September 19, 2019 among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on September 24, 2019, and incorporated herein by reference)
21.1*	Subsidiaries of Registrant
23.1*	Consent of Ernst & Young LLP
23.2*	Consent of Ryder Scott Company L.P.
24.1*	Power of Attorney
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002
99.1*	Ryder Scott Audit Letter
101.INS	Inline XBRL Instance Document - The instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH*	Inline XBRL Schema Document
101.CAL*	Inline XBRL Calculation Linkbase Document
101.LAB*	Inline XBRL Label Linkbase Document
101.PRE*	Inline XBRL Presentation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101.INS)

* Filed with this report.
** Furnished with this report.
*** Certain portions of this exhibit have been redacted and are subject to a confidential treatment order granted by the Securities and Exchange Commission pursuant to Rule 24b-2 under the Exchange Act.
† Exhibit constitutes a management contract or compensatory plan or agreement.
†† Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on July 30, 2010 primarily to reflect the change in the name of the registrant from St. Mary Land & Exploration Company to SM Energy Company. There were no material changes to the substantive terms and conditions in this document.
\+ Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on November 9, 2010, in order to make technical revisions to ensure compliance with Section 409A of the Internal Revenue Code. There were no material changes to the substantive terms and conditions in this document.

(c) Financial Statement Schedules. Please refer to Item 15(a) above.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

SM ENERGY COMPANY

(Registrant)

Date:	February 20, 2020	By:	/s/ JAVAN D. OTTOSON
			Javan D. Ottoson
			President and Chief Executive Officer
			(Principal Executive Officer)

GENERAL POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Javan D. Ottoson and A. Wade Pursell his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2019, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

Pursuant to the requirements of 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.

Signature	Title	Date
/s/ JAVAN D. OTTOSON Javan D. Ottoson	President, Chief Executive Officer, and Director (Principal Executive Officer)	February 20, 2020
/s/ A. WADE PURSELL A. Wade Pursell	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 20, 2020
/s/ PATRICK A. LYTLE Patrick A. Lytle	Controller and Assistant Secretary (Principal Accounting Officer)	February 20, 2020

Signature	Title	Date
/s/ WILLIAM D. SULLIVAN William D. Sullivan	Chairman of the Board of Directors	February 20, 2020
/s/ CARLA J. BAILO Carla J. Bailo	Director	February 20, 2020
/s/ LARRY W. BICKLE Larry W. Bickle	Director	February 20, 2020
/s/ STEPHEN R. BRAND Stephen R. Brand	Director	February 20, 2020
/s/ LOREN M. LEIKER Loren M. Leiker	Director	February 20, 2020
/s/ RAMIRO G. PERU Ramiro G. Peru	Director	February 20, 2020
/s/ JULIO M. QUINTANA Julio M. Quintana	Director	February 20, 2020
/s/ ROSE M. ROBESON Rose M. Robeson	Director	February 20, 2020

EXHIBIT 4.11

DESCRIPTION OF SECURITIES

As of December 31, 2019, SM Energy Company has registered one class of securities under Section 12 of the Securities Exchange Act of 1934, as amended (the "**Exchange Act**").

Description of Common Stock

The following description of our Common Stock is a summary and does not purport to be complete. It is subject to, and qualified in its entirety by, reference to our Restated Certificate of Incorporation (the "**Certificate of Incorporation**") and our Amended and Restated By-laws (the "**Bylaws**"), each of which are incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit is a part. We encourage you to read our Certificate of Incorporation, our Bylaws and the applicable provisions of the Delaware General Corporate Law, for additional information.

Authorized Capital Shares

Our authorized capital shares consist of 200,000,000 shares of capital stock, $0.01 par value per share. We have outstanding shares of common stock ("**Common Stock**"). The outstanding shares of our Common Stock are fully paid and non-assessable. This means the full purchase price for the outstanding shares of Common Stock has been paid and the holders of such shares will not be assessed any additional amounts for such shares. Any additional shares of Common Stock that the Company may issue in the future will also be fully paid and non-assessable.

The Certificate of Incorporation provides that authorized but unissued shares of Common Stock are available for future issuance without stockholder approval, subject to various limitations imposed by the New York Stock Exchange ("**NYSE**"). These additional shares of Common Stock may be utilized for a variety of corporate purposes, including future public offerings to raise additional capital, corporate acquisitions and employee benefit plans. The existence of authorized but unissued shares of Common Stock could make it more difficult or discourage an attempt to obtain control of the Company by means of a proxy contest, tender offer, merger or otherwise.

Voting Rights

Each share of Common Stock is entitled to one vote on all matters submitted to a vote of the stockholders, including the election of directors. Our Common Stock does not have cumulative voting rights. This means a holder of a single share of Common Stock cannot cast more than one vote for each position to be filled on the Board of Directors. It also means the holders of a majority of the shares of Common Stock entitled to vote in the election of directors can elect all directors standing for election and the holders of the remaining shares will not be able to elect any directors.

Dividend Rights

The holders of Common Stock are entitled to receive ratably such dividends, if any, as may be declared from time to time by the Board of Directors in its discretion out of funds legally available for the payment of dividends. Delaware law allows a corporation to pay dividends only out of surplus, as determined under Delaware law.

Liquidation Rights

Upon the liquidation, dissolution or winding up of the Company, the holders of Common Stock are entitled to receive ratably the net assets of the Company legally available for distribution.

Other Rights and Preferences

Our Common Stock has no sinking fund provision or preemptive, subscription or conversion rights. The holders of Common Stock may act by unanimous written consent.

Listing

Our Common Stock is traded on the NYSE under the trading symbol "SM."

EXHIBIT 10.17

SUMMARY OF COMPENSATION ARRANGEMENTS FOR NON-EMPLOYEE DIRECTORS

The following is a description of the standard arrangements pursuant to which directors of SM Energy are compensated for services provided as a director, including additional amounts payable for committee participation:

DIRECTOR COMPENSATION

Employee directors do not receive additional compensation for serving on the Board of Directors or any committee.

For service in 2019 - 2020 as it relates to the period from May 2019 through May 2020, target compensation for each member of the Board of Directors has been set at $126,000 annually, plus a retainer paid in lieu of committee and attendance fees. As described more fully below, the actual value of compensation may be higher or lower depending on the results of the restricted stock component of director compensation. Primary director compensation is in the form of stock grants and is fully described below. The retainer component of director compensation for non-employee directors consists of an annual retainer of $90,000 for committee and board meeting fees paid in SM Energy common stock or cash as selected by the director; provided that in the event any director attends in excess of 30 Board and Committee meetings in the aggregate during the period from May 2019 through May 2020, such director shall receive $1,500 per meeting for each meeting in excess of 30. In addition, each non-employee director is reimbursed for expenses incurred in attending Board and Committee meetings and director education programs.

The committee chairs receive the cash payments identified in the list below in recognition of the additional workload of their respective committee assignments. These amounts are paid at the beginning of the annual service period.

- Audit Committee - $20,000
- Compensation Committee - $15,000
- Nominating and Corporate Governance Committee - $10,000

The stock compensation for non-employee directors is as follows:

Annual compensation payable upon election to the Board by the stockholders, valued at $126,000. This resulted in a grant of restricted stock to each non-employee director of 10,345 shares of SM Energy common stock issued on May 30, 2019, under SM Energy's Equity Incentive Compensation Plan. These shares vested on December 31, 2019.

A retainer for the Non-Executive Chairman of the Board valued at $80,000. This resulted in a grant of 6,569 shares of SM Energy common stock issued on May 30, 2019, under SM Energy's Equity Incentive Compensation Plan. These shares vested on December 31, 2019.

William Sullivan elected to receive SM Energy common stock for his retainer, which resulted in a grant of 7,390 shares of SM Energy common stock issued on May 30, 2019, under SM Energy's Equity Incentive Compensation Plan. These shares vested on December 31, 2019. Carla Bailo, Larry Bickle, Stephen Brand, Loren Leiker, Ramiro Peru, Julio Quintana and Rose Robeson each elected to receive a $90,000 cash payment for their retainer.

EXHIBIT 21.1

SUBSIDIARIES
OF
SM ENERGY COMPANY

A. Wholly-owned subsidiaries of SM Energy Company, a Delaware corporation:

1. SMT Texas LLC, a Colorado limited liability company
2. Belring GP LLC, a Delaware limited liability company
3. St. Mary Energy Louisiana LLC, a Delaware limited liability company
4. Hilltop Investments, a Colorado general partnership
5. Parish Ventures, a Colorado general partnership
6. Green Canyon Offshore LLC, a Delaware limited liability company

B. Partnership or limited liability company interests held by SM Energy Company:

1. Potato Creek Midstream, LLC, a Pennsylvania limited liability company (70%)
2. 1977 H.B Joint Account, a Colorado general partnership (8%)
3. 1976 H.B Joint Account, a Colorado general partnership (9%)
4. 1974 H.B Joint Account, a Colorado general partnership (4%)

C. Partnership interests held by SMT Texas, LLC:

1. St. Mary Land East Texas LP, a Texas limited partnership (99%) (the remaining 1% interest is held by SM Energy Company)

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Post-Effective Amendment No. 1 to Registration Statement (Form S-8 Nos. 333-30055, 333-106438, 333-35352, and 333-88780) of SM Energy Company,
(2) Registration Statement (Form S-8 Nos. 333-58273, 333-134221, 333-151779, 333-165740, 333-170351, 333-194305, 333-212359, 333-219719, and 333-226660) of SM Energy Company,
(3) Post-Effective Amendment No. 1 to Registration Statement (Form S-3 No. 333-203936 and 333-226597) of SM Energy Company, and
(4) Registration Statement (Form S-3 No. 333-216843) of SM Energy Company;

of our reports dated February 20, 2020, with respect to the consolidated financial statements of SM Energy Company and subsidiaries, and the effectiveness of internal control over financial reporting of SM Energy Company and subsidiaries, included in this Annual Report (Form 10-K) of SM Energy Company and subsidiaries for the year ended December 31, 2019.

/s/ Ernst & Young LLP

Denver, Colorado
February 20, 2020

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of SM Energy Company for the year ended December 31, 2019. We hereby further consent to the use of information contained in our reports, and the use of our audit letter, as of December 31, 2019, relating to estimates of revenues from SM Energy Company's oil, gas, and NGL reserves. We further consent to the incorporation by reference thereof into SM Energy Company’s Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-106438, 333-35352, and 333-88780 on Form S-8, Registration Statement Nos. 333-58273, 333-134221, 333-151779, 333-165740, 333-170351, 333-194305, 333-212359, 333-219719, and 333-226660 on Form S-8, Post-Effective Amendment No. 1 to Registration Statement No. 333-203936 and 333-226597 on Form S-3, and Registration Statement No. 333-216843 on Form S-3.

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

Houston, Texas
February 20, 2020

EXHIBIT 31.1

CERTIFICATION

I, Javan D. Ottoson, certify that:

1. I have reviewed this annual report on Form 10-K of SM Energy Company;

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 statements 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 are 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 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 officer 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 the 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 control 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 control over financial reporting.

Date: February 20, 2020

/s/ JAVAN D. OTTOSON
Javan D. Ottoson
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, A. Wade Pursell, certify that:

1. I have reviewed this annual report on Form 10-K of SM Energy Company;

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 statements 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 are 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 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 officer 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 the 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 control 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 control over financial reporting.

Date: February 20, 2020

/s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and Chief Financial and Accounting Officer

EXHIBIT 32.1

CERTIFICATION

PURSUANT TO

18 U.S.C. SECTION 1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of SM Energy Company (the “Company”) for the fiscal year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Javan D. Ottoson, as President and Chief Executive Officer of the Company, and A. Wade Pursell, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

(1) 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 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.

/s/ JAVAN D. OTTOSON
Javan D. Ottoson
President and Chief Executive Officer
February 20, 2020

/s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and Chief Financial and Accounting Officer
February 20, 2020

EXHIBIT 99.1

SM ENERGY COMPANY

Estimated

Future Reserves

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2019

/s/ Michael F. Stell	/s/ Val Rick Robinson
Michael F. Stell, P.E.	Val Rick Robinson
TBPE License No. 56416	TBPE License No. 105137
Advising Senior Vice President	Managing Senior Vice President

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

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235
FAX (713) 651-0849
TELEPHONE (713) 651-9191

January 3, 2020

Mr. Levi J. Briese
Reserves Engineering Supervisor
SM Energy Company
1775 Sherman Street, Suite 1200
Denver, Colorado 80203

Gentlemen:

At the request of SM Energy Company (SM Energy), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2019 prepared by SM Energy's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party reserves audit, completed on December 23, 2019 and presented herein, was prepared for public disclosure by SM Energy in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent SM Energy's estimated net reserves attributable to the leasehold interests in certain properties owned by SM Energy and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2019. The properties reviewed by Ryder Scott incorporate 1,141 SM Energy reserves determinations and are located in the state of Texas.

The properties reviewed by Ryder Scott account for a portion of SM Energy's total net proved reserves as of December 31, 2019. Based on the estimates of total net proved reserves prepared by SM Energy, the reserves audit conducted by Ryder Scott addresses 96 percent of the total proved developed net liquid hydrocarbon reserves, 98 percent of the total proved developed net gas reserves, 69 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 63 percent of the total proved undeveloped net gas reserves of SM Energy.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties

Based on our review, including the data, technical processes and interpretations presented by SM Energy, it is our opinion that the overall procedures and methodologies utilized by SM Energy in preparing their estimates of the proved reserves as of December 31, 2019 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by SM Energy are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. SM Energy has informed us that in the preparation of their reserves and income projections, as of December 31, 2019, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by SM Energy attributable to SM Energy's interest in properties that we reviewed and for those that we did not review are summarized below:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold Interests of
SM Energy Company

As of December 31, 2019

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves of Properties Audited by Ryder Scott				
Oil/Condensate - MBBL	76,295	3,804	76,781	156,880
Plant Products - MBBL	42,884	115	12,471	55,470
Gas – MMCF	687,964	9,697	321,346	1,019,007
Net Reserves of Properties Not Audited by Ryder Scott				
Oil/Condensate - MBBL	3,588	1,277	22,342	27,207
Plant Products - MBBL	253	156	18,135	18,544
Gas – MMCF	10,928	3,467	189,772	204,167
Total Net Reserves				
Oil/Condensate - MBBL	79,883	5,081	99,123	184,087
Plant Products - MBBL	43,137	271	30,606	74,014
Gas – MMCF	698,892	13,164	511,118	1,223,174

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBBL). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The proved reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the shut-in category.

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

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

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

Audit Data, Methodology, Procedure and Assumptions

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

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

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

The proved reserves, prepared by SM Energy, for the properties that we reviewed were estimated by performance methods, analogy, or a combination of methods. All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. The performance methods, such as decline curve analysis, utilized extrapolations of historical production data available through November 2019 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by SM Energy or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved non-producing and undeveloped reserves included herein were estimated by analogy. The analogs utilized data furnished to Ryder Scott by SM Energy or which we have obtained from public data sources that were available through November 2019.

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

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by SM Energy relating to hydrocarbon prices and costs as noted herein.

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

The initial SEC hydrocarbon prices in effect on December 31, 2019 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by SM Energy for the geographic area reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used by SM Energy to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used by SM Energy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SM Energy.

The table below summarizes SM Energy’s net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as SM Energy’s “average realized prices.” The average realized prices shown in the table below were determined from SM Energy’s estimate of the total future gross revenue before production taxes for the properties reviewed by us and SM Energy’s estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for the geographic area reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI, Cushing	$55.69/BBL	$53.67/BBL
	NGLs	OPIS Composite(1)	$22.68/BBL	$18.62/BBL
	Gas	Henry Hub	$2.58/MMBTU	$2.53/MCF

(1) Price reflects composition of ethane, propane, and butane

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

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by SM Energy are based on the operating expense reports of SM Energy and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished by SM Energy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SM Energy. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by SM Energy are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by SM Energy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SM Energy. The estimated net cost of abandonment and salvage was included by SM Energy for properties where abandonment costs and salvage were material. SM Energy's estimates of the net abandonment costs were accepted without independent verification.

The proved undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with SM Energy's plans to develop these reserves as of December 31, 2019. The implementation of SM Energy's development plans as presented to us is subject to the approval process adopted by SM Energy's management. As the result of our inquiries during the course of our review, SM Energy has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by SM Energy's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to SM Energy. SM Energy has provided written documentation supporting their commitment to proceed with the development activities as presented to us**.** Additionally, SM Energy has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2019, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

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

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

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

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

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

The estimates of proved reserves presented herein were based upon a review of the properties in which SM Energy owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by SM Energy for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of SM Energy are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

SM Energy has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of SM Energy's forecast of future proved production, we have relied upon data furnished by SM Energy with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by SM Energy. The data described herein were accepted as authentic and sufficient for determining the reserves unless, during the course of our examination, a matter of question came to our attention in which case the data were not accepted until all questions were satisfactorily resolved. We consider the factual data furnished to us by SM Energy to be appropriate and sufficient for the purpose of our review of SM Energy's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by SM Energy and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by SM Energy, it is our opinion that the overall procedures and methodologies utilized by SM Energy in preparing their estimates of the proved reserves as of December 31, 2019 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by SM Energy are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the

SPE auditing standards. Ryder Scott found the processes and controls used by SM Energy in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with SM Energy's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between SM Energy's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to SM Energy when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by SM Energy.

Other Properties

Other properties, as used herein, are those properties of SM Energy which we did not review. The proved net reserves attributable to the other properties account for 18 percent of the total proved net liquid hydrocarbon reserves and 17 percent of the total proved net gas reserves based on estimates prepared by SM Energy as of December 31, 2019. The other properties represent 13 percent of the total proved discounted future net income at 10% based on the unescalated pricing policy of the SEC as taken from reserves and income projections prepared by SM Energy as of December 31, 2019.

The same technical personnel of SM Energy were responsible for the preparation of the reserves estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

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

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

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

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

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

Terms of Usage

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

SM Energy makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, SM Energy has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-8 of SM Energy, of the references to our name, as well as to the references to our third party report for SM Energy, which appears in the December 31, 2019 annual report on Form 10-K of SM Energy. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by SM Energy.

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

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

Very truly yours,

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

/s/ Michael F. Stell

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MFS-VRR (LPC)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Michael F. Stell was the primary technical person responsible for overseeing the estimate of the reserves, future production and income.

Mr. Stell, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 1992, is an Advising Senior Vice President and is responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Stell served in a number of engineering positions with Shell Oil Company and Landmark Concurrent Solutions. For more information regarding Mr. Stell's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Stell earned a Bachelor of Science degree in Chemical Engineering from Purdue University in 1979 and a Master of Science Degree in Chemical Engineering from the University of California, Berkeley, in 1981. He is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Stell fulfills. As part of his 2009 continuing education hours, Mr. Stell attended an internally presented 13 hours of formalized training as well as a day-long public forum relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Stell attended an additional 15 hours of formalized in-house training as well as an additional five hours of formalized external training during 2009 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants. As part of his 2010 continuing education hours, Mr. Stell attended an internally presented six hours of formalized training and ten hours of formalized external training covering such topics as updates concerning the implementation of the latest SEC oil and gas reporting requirements, reserve reconciliation processes, overviews of the various productive basins of North America, evaluations of resource play reserves, evaluation of enhanced oil recovery reserves, and ethics training. For each year starting 2011 through 2019, as of the date of this report, Mr. Stell has 20 hours of continuing education hours relating to reserves, reserve evaluations, and ethics.

Based on his educational background, professional training and over 37 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Stell has attained the professional qualifications for a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basincentered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

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).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

(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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are 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
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
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
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.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

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.

(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.