SM Energy Co
Form 10-K
February 21, 2019

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
þ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2018
or
o 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	Name of each exchange on which registered
Common stock, $.01 par value	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 þ No o

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 o No þ

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 þ No o

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 þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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 þ Accelerated filer o

Non-accelerated filer o Smaller reporting company o

Emerging growth company o

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. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No þ

The aggregate market value of the 110,740,087 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 29, 2018, the last business day of the registrant's most recently completed second fiscal quarter, of $25.69 per share, as reported on the New York Stock Exchange, was $2,844,912,835. 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 7, 2019, the registrant had 112,243,245 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 2019 annual meeting of stockholders to be filed within 120 days after December 31, 2018.

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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 under Glossary of Oil and Gas Terms. Throughout this document we make statements that may be classified as "forward-looking." Please refer to the Cautionary Information about Forward-Looking Statements section of this document for an explanation of these types of statements.

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

We are an independent energy company engaged in the development, production, exploration, and acquisition of crude oil and condensate, natural gas, and natural gas liquids (also respectively referred to as "oil," "gas," and "NGLs" throughout the document) in onshore North America. We were founded in 1908 and incorporated in Delaware in 1915. 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

Our strategic objective is to be a premier operator of top tier assets. We pursue growth opportunities through both acquisitions and exploration, and we seek to maximize the value of our assets through industry leading technology and outstanding operational execution. We are focused on generating strong full-cycle economic returns on our investments and maintaining a strong balance sheet.

Significant Developments in 2018

Reserves and Capital Investment. Our estimated proved reserves increased eight percent to 503.4 MMBOE at December 31, 2018, from 468.1 MMBOE at December 31, 2017. Reserve additions from discoveries, extensions, and infills were 188.0 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. These positive results for 2018 were partially offset by the divestiture of 40.3 MMBOE of estimated proved reserves, and net downward revisions of 68.8 MMBOE, which resulted primarily from changes in our development plans in our Eagle Ford shale program. On a retained asset basis, estimated proved reserves increased 18 percent year-over-year. Our proved reserve life index increased to 11.5 years as of December 31, 2018, compared with 10.5 years as of December 31, 2017. Costs incurred for development and exploration activities, excluding acquisitions, increased 41 percent from the prior year to $1.3 billion in 2018. Please refer to Areas of Operation and Reserves below, and to the caption Oil and Gas Reserve Quantities in the Supplemental Oil and Gas Information section in Part II, Item 8 of this report for additional discussion.

Production. Our average daily production in 2018 consisted of 51.4 MBbl of oil, 282.7 MMcf of gas, and 21.8 MBbl of NGLs, for an average net daily equivalent production rate of 120.3 MBOE, which represents a one percent decrease compared with 2017. Our Permian region realized a 91 percent increase in production volumes during 2018, compared with 2017, as a result of ramping up development activities and realizing stronger than expected well results. Increased production volumes from our Permian region were offset by the divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018 and decreased production volumes from our Eagle Ford shale assets as a result of reduced capital investment in this area. On a retained asset basis, our production volumes increased 11 percent in 2018. Please refer to Areas of Operation below for additional discussion.

Net Cash Provided by Operating Activities. Net cash provided by operating activities was $720.6 million for the year ended December 31, 2018, compared with $515.4 million for the year ended December 31, 2017, which was an increase of 40 percent year-over-year. The increase in net cash provided by operating activities for 2018, compared with 2017, was primarily the result of 37 percent growth in higher margin oil production, which, combined with increased benchmark pricing for oil and NGLs, drove a 32 percent increase in our realized price per BOE before the effects of derivative settlements, and led to a 31 percent increase in oil, gas, and NGL production revenue. Partially offsetting the increase from oil, gas, and NGL production revenue was a cash settlement loss on derivatives of $135.8 million for the year ended December 31, 2018, compared to a cash settlement gain on derivatives of $21.2 million for 2017. Please refer to Analysis of Cash Flow Changes Between 2018 and 2017 and Between 2017 and 2016 in Part II,

Item 7 and Note 10 – Derivative Financial Instruments in Part II, Item 8 of this report for additional discussion.
Divestiture Activity. During the first quarter of 2018, we successfully completed the divestiture of our Powder River Basin assets (the "PRB Divestiture") for total cash consideration, 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. During the second quarter of 2018, we completed divestitures of our remaining assets in the Williston Basin located in Divide County, North Dakota (the "Divide County Divestiture") and our non-operated Halff East assets in the Midland Basin (the "Halff East Divestiture"), for combined net divestiture proceeds of $252.2 million, and a final

net gain of $15.4 million. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions in Part II, Item 8 of this report for additional discussion.

Long-Term Debt Reduction. During 2018 we completed multiple transactions that resulted in overall long-term debt reduction and extension of the average maturity date for our remaining long-term debt. Total principal outstanding for long-term debt decreased from $3.0 billion at year end 2017, to $2.6 billion at year end 2018, and was accomplished through the redemption of our 6.50% Senior Notes due 2021 ("2021 Senior Notes") using cash proceeds from divestitures. We also successfully extended the average maturity of our remaining long-term debt obligations by issuing 6.625% Senior Notes due 2027 ("2027 Senior Notes") and using the net proceeds from this issuance to repurchase our 6.50% Senior Notes due 2023 ("2023 Senior Notes") and a portion of our 6.125% Senior Notes due 2022 ("2022 Senior Notes"). Please refer to Note 5 – Long-Term Debt in Part II, Item 8 of this report for additional discussion.

Outlook

We remain focused on maximizing the returns and increasing the value of our top tier capital project inventory in the Midland Basin and Eagle Ford shale. We expect to do this through exploration, acquisitions, and further development optimization. These assets will allow for production growth while maximizing internally generated cash flows, which will also support our priorities for improving our credit metrics and maintaining strong financial flexibility.

Our capital program for 2019, excluding acquisitions, is expected to range from $1.00 billion to $1.07 billion. We expect our program to concentrate on developing our top tier assets in the Midland Basin and Eagle Ford shale, with the majority of our 2019 capital being allocated to our Midland Basin program. Planned drilling and completion activity in the Eagle Ford shale will continue to be partially funded by a third-party as part of our joint venture agreement, which was extended into 2019 to include 12 additional wells that we expect to be completed in 2019. Please refer to the caption Outlook in the Overview of the Company section and Overview of Liquidity and Capital Resources, under Part II, Item 7 of this report for additional discussion of our financing and capital plans for 2019.

Areas of Operation

Our 2018 operations were concentrated in our onshore Permian and South Texas & Gulf Coast regions in the United States. We divested all remaining producing assets in the Rocky Mountain region in the first half of 2018. The following table summarizes estimated proved reserves, production, and costs incurred in oil and gas activities for the year ended December 31, 2018, for these regions:

	Permian		South Texas & Gulf Coast		Rocky Mountain		Total [1]	
Proved reserves								
Oil (MMBbl)	159.4		16.3		—		175.7	
Gas (Bcf)	328.4		993.4		—		1,321.8	
NGLs (MMBbl)	0.2		107.2		—		107.4	
MMBOE [1]	214.3		289.1		—		503.4	
Relative percentage	43	%	57	%	—	%	100	%
Proved developed %	40	%	55	%	N/A		49	%
Production								
Oil (MMBbl)	16.6		1.3		0.9		18.8	
Gas (Bcf)	25.8		76.2		1.2		103.2	
NGLs (MMBbl)	—		7.9		—		7.9	
MMBOE [1]	20.9		21.8		1.1		43.9	
Avg. daily equivalents (MBOE/d) [1]	57.4		59.9		3.1		120.3	
Relative percentage	48	%	50	%	2	%	100	%
Costs incurred (in millions) [2] [3]	$1,180.9		$185.3		$ 2.7		$1,389.5	

(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 the caption Costs Incurred in Oil and Gas Producing Activities in the Supplemental Oil and Gas Information section in Part II, Item 8 of this report.

(3) Costs incurred for 2018 included $57.0 million relating to acquisitions of primarily unproved oil and gas properties in our Permian region. Please refer to Costs Incurred in Oil and Gas Producing Activities in Supplemental Oil and Gas Information in Part II, Item 8 of this report.

Excluding acquisition activity, costs incurred increased in 2018 by 41 percent compared with the prior year as we continued to accelerate development activities in our Permian region. Total estimated proved reserves at year end 2018 increased eight percent from the prior year and increased 18 percent on a retained asset basis. Production decreased one percent on an equivalent basis for the year ended December 31, 2018, compared with 2017, but increased 11 percent on a retained asset basis.

Permian Region. Operations in our Permian region are managed from our regional office in Midland, Texas. In 2018, we focused on continuing to delineate, develop, and expand our Midland Basin position in western Texas. Our approximately 79,800 net acre position as of December 31, 2018, excludes approximately 1,885 net acres associated with drill-to-earn opportunities we plan to pursue, and is lower than our year end 2017 net acreage position as a result of the Halff East Divestiture, which reduced our Midland Basin position by approximately 5,400 net acres year-over-year. Our current Midland Basin position provides for substantial future development opportunities within multiple oil-rich intervals, including the Spraberry and Wolfcamp formations.

We incurred approximately $1.2 billion of costs and added approximately 78.3 MMBOE of estimated proved reserves, net of price and performance revisions, through our drilling and completion activities in 2018. 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. Capital was also invested in our water transportation and handling facilities, which began operations in mid-2018 and now serve a significant portion of our disposal needs on our RockStar acreage. During

2018, we operated an average of seven drilling rigs and four completion crews. As of December 31, 2018, we had six drilling rigs and three completion crews running in the Midland Basin, primarily focused on developing our RockStar acreage. Estimated proved reserves increased 34 percent to 214.3 MMBOE at year end 2018, from 159.9 MMBOE at year end 2017. We completed 114 gross (104 net) wells during 2018, and full-year production increased 91 percent year-over-year to 20.9 MMBOE for 2018.

As of December 31, 2018, there were 61 gross (55 net) wells that had been drilled but not completed in our Midland Basin program.

South Texas & Gulf Coast Region. Operations in our South Texas & Gulf Coast region are managed from our regional office in Houston, Texas. This region is primarily comprised of our Eagle Ford shale position, which includes approximately 163,000 contiguous net acres. Our acreage position in the Eagle Ford shale covers a significant portion of the western Eagle Ford shale play and includes acreage across the gas-condensate and dry gas windows of the play with gas composition amenable to processing for NGL extraction.

In 2018, we incurred $185.3 million of costs and added approximately 40.8 MMBOE of estimated proved reserves, net of revisions, primarily as a result of a net increase in proved undeveloped reserves resulting from changes to our future development plans, and positive price revisions. During 2018, we averaged one drilling rig and one completion crew on our Eagle Ford shale acreage. Estimated proved reserves increased five percent to 289.1 MMBOE at year end 2018, from 275.2 MMBOE at year end 2017. We completed 40 gross (26 net) wells during 2018 on our operated acreage, and full-year regional production decreased 26 percent year-over-year to 21.8 MMBOE for 2018. The decrease in production from our Eagle Ford shale program was primarily driven by the sale of our outside-operated assets in the first quarter of 2017, reduced capital investment on our retained operated acreage, and reduced working and revenue interests associated with certain Eagle Ford shale wells as a result of the joint venture agreement discussed below.

In September 2017, we entered into a joint venture agreement with a third-party to drill 16 wells and complete 23 wells in a focused portion of our Eagle Ford North area (“Phase 1 JV”). In December 2018, we extended this agreement and added an additional 12 wells to be drilled and completed (“Phase 2 JV”). The agreement provides that the third-party carries 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 allows 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 Phase 1 JV wells were drilled and completed as of December 31, 2018. Six of the 12 Phase 2 JV wells were drilled during 2018, and we expect the remaining six wells to be drilled and all 12 wells to be completed during 2019.

As of December 31, 2018, there were 29 gross (23 net) wells that had been drilled but not completed in our South Texas & Gulf Coast region.

Rocky Mountain Region. We divested all remaining producing assets in the Rocky Mountain region in the first half of 2018. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions in Part II, Item 8 of this report for additional discussion.

Reserves

The table below presents summary information with respect to the estimates of our proved reserves for each of the years in the three-year period ended December 31, 2018. We engaged Ryder Scott Company, L.P. (“Ryder Scott”) to audit at least 80 percent of our total calculated estimated proved reserve PV-10 for each year presented. 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 Securities and Exchange Commission (“SEC”) rules, and were $65.56 per Bbl for oil, $3.10 per MMBtu for gas, and $33.45 per Bbl for NGLs for the year ended December 31, 2018. We then adjusted these prices to reflect appropriate quality and location differentials over the period in estimating our proved 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. PV-10 shown in the following table 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 PV-10 nor the standardized measure of discounted future net cash flows 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 our production is critical to us. 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, PV-10, and reserve life index as of December 31, 2018, 2017, and 2016:

	As of December 31,		
	2018	2017	2016
Reserve data:			
Proved developed			
Oil (MMBbl)	68.2	58.6	48.5
Gas (Bcf)	699.1	642.9	609.1
NGLs (MMBbl)	60.1	49.0	58.6
MMBOE [(1)]	244.8	214.7	208.7
Proved undeveloped			
Oil (MMBbl)	107.6	99.6	56.4
Gas (Bcf)	622.7	637.2	502.0
NGLs (MMBbl)	47.2	47.6	47.1
MMBOE [(1)]	258.6	253.4	187.1
Total proved [(1)]			
Oil (MMBbl)	175.7	158.2	104.9
Gas (Bcf) [(2)]	1,321.8	1,280.1	1,111.1
NGLs (MMBbl)	107.4	96.5	105.7
MMBOE	503.4	468.1	395.8
Proved developed reserves %	49 %	46 %	53 %
Proved undeveloped reserves %	51 %	54 %	47 %
Reserve data (in millions):			
Standardized measure of discounted future net cash flows (GAAP)	$4,654.4	$3,024.1	$1,152.1
PV-10 (non-GAAP):			
Proved developed PV-10	$3,084.2	$1,984.2	$1,051.1
Proved undeveloped PV-10	2,020.1	1,072.3	101.0
Total proved PV-10 (non-GAAP)	$5,104.3	$3,056.5	$1,152.1
Reserve life index (years)	11.5	10.5	7.2

(1) Amounts may not calculate due to rounding.

(2) For the years ended December 31, 2018, 2017, and 2016, proved gas reserves contained 59.1 Bcf, 48.1 Bcf, and 43.7 Bcf of gas, respectively, that we expect to produce and use as a field equipment fuel source (primarily to power compressors).

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

	As of December 31,		
	2018	2017	2016
	(in millions)		
Standardized measure of discounted future net cash flows (GAAP)	$4,654.4	$3,024.1	$1,152.1
Add: 10 percent annual discount, net of income taxes	3,847.1	2,573.2	937.1
Add: future undiscounted income taxes	1,012.2	205.7	—
Undiscounted future net cash flows	9,513.7	5,803.0	2,089.2
Less: 10 percent annual discount without tax effect	(4,409.4)	(2,746.5)	(937.1)
PV-10 (non-GAAP)	$5,104.3	$3,056.5	$1,152.1

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, 2018, 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 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 258.6 MMBOE of total proved undeveloped reserves as of December 31, 2018, approximately 81.4 MMBOE of proved undeveloped reserves in our Wolfcamp and Lower Spraberry shale positions in the Midland Basin and 71.4 MMBOE of proved undeveloped reserves in our Eagle Ford shale 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, 2018, estimated proved undeveloped reserves totaled 258.6 MMBOE, which was an increase of 5.2 MMBOE, or two percent, from 253.4 MMBOE at December 31, 2017. The following table provides a reconciliation of our proved undeveloped reserves for the year ended December 31, 2018:

	Total (MMBOE)
Total proved undeveloped reserves:	
Beginning of year	253.4
Revisions of previous estimates	(54.4)
Additions from discoveries, extensions, and infill	151.7
Sales of reserves	(22.0)
Purchases of minerals in place	0.1
Removed for five-year rule	(22.6)
Conversions to proved developed	(47.6)
End of year	258.6

Revisions of previous estimates. Revisions of previous estimates includes a downward performance revision of 37.8 MMBOE from our Eagle Ford shale program as a result of optimizing our development plan. Offsetting these downward reserve revisions are proved undeveloped reserves in our Eagle Ford shale program that are engineered with wider spacing and longer lateral completions, which are reflected as additions from discoveries, extensions, and infill. In addition, we had downward performance revisions of 17.2 MMBOE in our Midland Basin program as we updated certain of our previous assumptions based on actual well results observed during the year.

Additions from discoveries, extensions, and infill. We added 67.6 MMBOE and 78.8 MMBOE of infill estimated proved undeveloped reserves in our Midland Basin and Eagle Ford shale programs, respectively, in 2018. We added an additional 5.3 MMBOE of estimated proved undeveloped reserves in the Midland Basin through various extensions and discoveries. The majority of additions in our Midland Basin program were the result of future development projects identified by our on-going development activities, while the majority of additions in our Eagle Ford shale program were from newly identified locations based on an optimized development plan that includes wider well

spacing and longer lateral completions.
Sales of reserves. Proved undeveloped reserves sold during the year primarily related to our PRB Divestiture, Divide County Divestiture, and Halff East Divestiture. There was also a reduction in proved undeveloped reserves as a result of the joint venture we executed in December 2018 for the development of certain Eagle Ford shale wells in which our working interest was reduced.

Removed for five-year rule. As a result of our testing and delineation efforts in 2018, we removed 22.6 MMBOE of estimated proved undeveloped reserves due to changes in our future development activities. Our development plans continue to be focused on maximizing returns and the value of our assets, and changes to these plans in 2018 caused these locations to be reclassified to unproved reserve categories and were replaced by higher quality proved undeveloped reserves, which are reflected as additions from discoveries, extensions, and infill.

Conversions to proved developed. Conversions of proved undeveloped reserves to proved developed reserves were in our Midland Basin and Eagle Ford shale programs. Our 2018 conversion track record was 19 percent. We expect our conversion track record to increase in 2019 as a result of increased capital expenditures related to converting proved undeveloped reserves. During 2018, we incurred $490.4 million on projects with reserves booked as proved undeveloped at the end of 2017, of which $442.4 million was spent on proved undeveloped reserves that converted to proved developed reserves by December 31, 2018. At December 31, 2018, drilled but not completed wells represented 40.1 MMBOE of total estimated proved undeveloped reserves. We expect to incur $254.3 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, 2018, estimated future development costs relating to our proved undeveloped reserves were $661.7 million, $457.7 million, and $599.1 million in 2019, 2020, and 2021, 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 10 years of experience in the energy industry and has been employed by the Company for nine 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. This data, 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 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 to be within 10 percent of our proved reserve amounts for the total company, as well as for each respective region. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum engineering consulting services throughout the world for over 70 years. The technical person at Ryder Scott primarily responsible for overseeing our reserves audit is a Managing Senior Vice President who received a Bachelor of Science degree in Chemical Engineering from Brigham Young University in 2003. He is a licensed Professional Engineer in the State of Texas and a member of the Society of Petroleum Engineers. The Ryder Scott 2018 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 - Operations, 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.

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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,		
	2018	2017	2016
Net production volumes			
Oil (MMBbl)	18.8	13.7	16.6
Gas (Bcf)	103.2	123.0	146.9
NGLs (MMBbl)	7.9	10.3	14.2
Equivalent (MMBOE) (1)	43.9	44.5	55.3
Midland Basin net production volumes (2)			
Oil (MMBbl)	16.6	8.5	2.6
Gas (Bcf)	25.8	14.7	5.6
NGLs (MMBbl)	—	—	—
Equivalent (MMBOE) (1)	20.9	11.0	3.5
Eagle Ford shale net production volumes (2)(3)			
Oil (MMBbl)	1.2	1.9	5.4
Gas (Bcf)	76.1	104.0	129.9
NGLs (MMBbl)	7.9	10.1	13.8
Equivalent (MMBOE) (1)	21.8	29.3	40.9
Realized price, before the effect of derivative settlements			
Oil (per Bbl)	$56.80	$47.88	$36.85
Gas (per Mcf)	$3.43	$3.00	$2.30
NGLs (per Bbl)	$27.22	$22.35	$16.16
Per BOE	$37.27	$28.20	$21.32
Production expense per BOE			
Lease operating expense	$4.74	$4.43	$3.51
Transportation costs	$4.36	$5.48	$6.16
Production taxes	$1.52	$1.18	$0.94
Ad valorem tax expense	$0.48	$0.34	$0.21

(1) Amounts may not calculate due to rounding.

(2) For each of the years ended December 31, 2018, and 2017, total estimated proved reserves attributed to our Midland Basin properties exceeded 15 percent of our total estimated proved reserves expressed on an equivalent basis. For each of the annual periods presented, total estimated proved reserves attributed to our Eagle Ford shale properties exceeded 15 percent of our total estimated proved reserves expressed on an equivalent basis.

(3) During the first quarter of 2017, we completed a divestiture of our outside-operated Eagle Ford shale assets. These assets represented approximately 1.5 MMBOE and 9.7 MMBOE of net production on an equivalent basis for the years ended December 31, 2017, and 2016, respectively.

Productive Wells

As of December 31, 2018, we had working interests in 715 gross (671 net) productive oil wells and 504 gross (485 net) productive gas wells. Productive wells are either wells producing in commercial quantities or wells mechanically capable of commercial production, but are temporarily shut-in. Multiple completions in the same wellbore are counted as one well. As of December 31, 2018, 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 production composition.

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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 2018, 2017, and 2016, 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,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Oil	103	92	56	46	100	73
Gas	39	24	38	35	114	56
Non-productive	—	—	4	3	2	1
	142	116	98	84	216	130
Exploratory wells						
Oil	18	14	32	29	7	7
Gas	1	1	—	—	—	—
Non-productive	—	—	1	—	—	—
	19	15	33	29	7	7
Total	161	131	131	113	223	137

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 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 plugged and abandoned.

In addition to the wells drilled and completed in 2018 (included in the table above), we were actively participating in the drilling of 21 gross (19 net) wells and had 104 gross (91 net) drilled but not completed wells as of January 31, 2019. These drilled but not completed wells represent wells that were being completed or were waiting on completion as of January 31, 2019.

Acreage

The following table sets forth the gross and net acres of developed and undeveloped oil and gas leasehold, fee properties, and mineral servitudes that we held as of December 31, 2018. 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	55,632	49,552	20,451	15,321	76,083	64,873
Sweetie Peck	15,176	14,189	3,736	772	18,912	14,961
Midland Basin Total [4]	70,808	63,741	24,187	16,093	94,995	79,834
Eagle Ford	73,926	73,549	92,379	89,443	166,305	162,992
Other [5]	16,278	11,368	262,059	188,994	278,337	200,362
Total	161,012	148,658	378,625	294,530	539,637	443,188

(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 7, 2019, approximately 1,406, 2,016, and 244 net acres of undeveloped acreage are scheduled to expire by December 31, 2019, 2020, and 2021, respectively, if production is not established or we take no other action to extend the terms of the applicable lease or leases.

(4) As of December 31, 2018, total Midland Basin acreage excludes approximately 1,885 net acres associated with drill-to-earn opportunities 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, 2018, we had gathering, processing, transportation throughput, and delivery commitments with various third-parties that require delivery of a minimum quantity of 29 MMBbl of oil, 595 Bcf of gas, and 21 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: a) our existing productive wells, b) future development of our proved undeveloped reserves, and c) 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.

In the event that no more product is delivered in accordance with these agreements, the aggregate undiscounted future deficiency payments as of December 31, 2018, would total $287.8 million. This amount does not include deficiency payment estimates associated with approximately 18.6 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 oil, gas, or NGLs would materially impact our operating results, as these are products with well-established markets and other viable purchaser options are available in our operating regions.

We had the following major customers and sales to entities under common ownership, which 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,		
	2018	2017	2016
Major customer #1 [(1)]	18%	6 %	—%
Major customer #2 [(1)]	10%	10%	5 %
Group #1 of entities under common ownership [(2)]	18%	17%	15%
Group #2 of entities under common ownership [(2)]	12%	8 %	8 %

(1) These major customers are purchasers of a portion of our production from our Permian region.

(2) In the aggregate, these groups of entities under common ownership represented 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 represented more than 10 percent of our total oil, gas, and NGL production revenue.

Employees and Office Space

As of February 7, 2019, we had 611 full-time employees. This is a four percent decrease from the 635 reported full-time employees as of February 14, 2018. 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, 2018, including our corporate headquarters and regional offices:

	Approximate Square Footage Leased
Corporate	107,000
Permian	59,000
South Texas & Gulf Coast	62,000
Mid-Continent [(1)]	50,000
Total	278,000

(1) During the third quarter of 2015, we closed our office in Tulsa, Oklahoma. We have subleased this space through the expiration of the lease, which will occur in September 2019.

In addition to the leased office space summarized in the table above, as of December 31, 2018, we owned a total of 79,000 square feet of office space in our South Texas & Gulf Coast and Rocky Mountain regions.

Title to Properties

Substantially all of our interests are held pursuant to oil and gas leases from third parties. We usually obtain title opinions prior to commencing our initial drilling operations on our properties. 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 Sixth Amended and Restated Credit Agreement (the “Credit Agreement”), royalty and overriding royalty interests, liens for current taxes, and other burdens that we believe do not materially interfere with the use of such properties. We typically perform title investigation in accordance with standards generally accepted in the oil and gas industry before acquiring undeveloped leasehold acreage.

Seasonality

Generally, but not always, the demand and price levels for gas increase during winter months and decrease during summer months. To lessen the impact of seasonal demand fluctuations, pipelines, utilities, local distribution companies, and industrial users 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 traditionally is placed into storage. This could reduce the typical seasonal price differential. Demand for energy is also generally higher in the winter and the summer driving season, although oil prices are impacted more significantly by global supply and demand. 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. See 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, own drilling rigs or other 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, and NGLs. 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 other fossil fuels such as coal and imported liquefied natural gas. 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 the competition for quality people, and we must compete effectively in order to be successful.

Government Regulations

Our business is extensively controlled by numerous federal, state, and local laws and governmental regulations. These laws and regulations may be changed from time to time 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

Many of the states in which we conduct our operations or own assets have 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 various state 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, state conservation laws sometimes 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.

Some of our operations are conducted on federal lands pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM"). These leases contain relatively standardized terms and require compliance with detailed regulations and orders that are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM before drilling and must comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure that lessee obligations are met. Under certain circumstances, the BLM may suspend or terminate our operations on federal leases.

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, tribal, 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" 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 greenhouse gases 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. See 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. 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 conducting our business in a manner that protects the environment and the health and safety of our employees, contractors and the public. We set annual goals for our environmental, health and safety program focused on reducing the number of safety related incidents that occur and the number and impact of spills of produced fluids. We also periodically conduct regulatory compliance audits of our operations to ensure compliance with all regulations and 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, releases of gas into the environment and flaring is an economic waste and reducing these volumes is a priority for us. To avoid flaring where possible, we restrict testing periods and make every effort to ensure that our production is connected 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.

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, 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," "estimate," "expect," "forecast," "intend," "pending," "plan," "project," "target," "will," and similar expre 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 Credit Agreement;
- our outlook on future oil, gas, and NGL prices, well costs, service costs, and general and administrative costs;
- the drilling of wells and other exploration and development activities and plans by us, our joint venture partners, and/or other third-party operators, as well as possible or expected acquisitions or divestitures;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- proved 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;
- cash flows, anticipated liquidity, interest and related debt service expenses, 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;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties; and
- other similar matters, such as those discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations section 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 a number of 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. Some of these risks are described in the Risk Factors section of this report, and include without limitation such factors as:

- domestic and foreign supply of oil, natural gas, and NGLs;
- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- weakness in economic conditions, consumer demand, and uncertainty in financial markets;

- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital required to develop and/or replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- our ability to attract and retain key personnel;
- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves, and that development of our proved undeveloped reserves may take longer and may require greater capital expenditures than we anticipate;
- the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on outside-operated properties;
- our reliance on the skill, expertise and availability of third-party service providers and equipment for our operated activities;
- the possibility that title to properties in which we claim an interest may be defective;
- our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;
- the uncertainties associated with acquisitions, divestitures, joint ventures, farm-downs, farm-outs and similar transactions with respect to certain assets, including our success in integrating new assets, and whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;
- the uncertainties associated with enhanced recovery methods;
- our commodity derivative contracts expose us to counterparty credit risk and may result in financial losses or may limit the prices we receive for oil, gas, and NGL sales;
- the inability of one or more of our service providers, customers, or contractual counterparties to meet their obligations;
- our ability to deliver required quantities of oil, gas, NGL, or water to contractual counterparties;
- price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;
- the impact that depressed oil, gas, or NGL prices could have on our borrowing capacity under our Credit Agreement;
- the possibility our amount of 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;
- the possibility that covenants in our Credit Agreement or the indentures governing the Senior Notes and 1.50% Senior Convertible Notes due July 1, 2021 (the “Senior Convertible Notes”) may limit our discretion in the operation of our business, prohibit us from engaging in beneficial transactions or lead to the accelerated payment of our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- the impact of extreme weather conditions, laws and regulations, and lease stipulations on our ability to conduct drilling activities;
- our ability to acquire adequate supplies of water and dispose of or recycle water we use at a reasonable cost in accordance with environmental and other applicable rules;
- complex laws and regulations, including environmental regulations, that result in substantial costs, delays, and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil, gas, and NGLs;
- new technologies may cause our current exploration and drilling methods to become obsolete;
- the possibility of security threats, including terrorist attacks and cybersecurity attacks and breaches, against, or otherwise impacting, our facilities and systems; and
- litigation, environmental matters, the potential impact of legislation and government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and actual results or performance may be materially different from those expressed or implied in the forward-looking statements. 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 securities laws.

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.

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 SEC's 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. 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 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.

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 2018 and Reserves within Part I, Items 1 and 2, Comparison of Financial Results and Trends Between 2018 and 2017 and Between 2017 and 2016 within Part II, Item 7, and Note 1 – Summary of Significant Accounting Policies, Note 11 – Fair Value Measurements, and Supplemental Oil and Gas Information 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;
- strengthening and weakening of the United States dollar relative to other currencies; 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, increased levels of unemployment, and an unprecedented level of intervention by the United States federal government and other governments. Although the United States economy appears to have stabilized, future uncertainty is possible. Renewed weakness in the United States 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 to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business, including for the exploration and/or development of reserves;

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- 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 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, or 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 and develop or 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 recent acquisitions, or any future acquisitions we may complete, a successful impact on 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 property acquisitions will not necessarily reveal, or allow us to fully assess, all existing or potential problems and deficiencies with the 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 special 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 obtain funding through 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.

In February 2016, Moody’s Investors Service and Standard & Poor’s downgraded our credit ratings (“Debt Rating”). 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, 2018, 51%, or 258.6 MMBOE, of our estimated proved reserves were proved undeveloped. In order to develop our proved undeveloped reserves, as of December 31, 2018, we estimate approximately $2.6 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 PV-10 or the standardized measure of discounted future net cash flows 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, 2018, was estimated using 12-month average sales prices of $65.56 per Bbl of oil (NYMEX WTI spot price), $3.10 per MMBtu of gas (NYMEX Henry Hub spot price), and $33.45 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 2018, our monthly average realized oil prices before the effect of derivative settlements were as high as $64.02 per Bbl and as low as $41.87 per Bbl, were as high as $34.56 per Bbl and as low as $19.59 per Bbl for NGLs, and were as high as $4.04 per Mcf and as low as $2.70 per Mcf for gas. 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 and obtain title opinions only on significant properties that we drill. 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 our newer resource plays, including those plays where we have recently acquired acreage, 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 7, 2019, that is scheduled to expire over the ensuing three years, represents approximately one percent of our total net undeveloped acreage as of December 31, 2018. 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 gas, and swap arrangements for 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, 2018, we were in a net accrued asset position of $158.3 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 regions for our oil, gas, and NGL production. Please refer to Note 1 – Summary of Significant Accounting Policies, under the heading Concentration of Credit Risk and Major Customers 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, 2018, we were contractually committed to deliver 29 MMBbl of oil, 595 Bcf of gas, and 21 MMBbl of produced water. These contracts expire at various dates 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, and other inherent acreage risks. For the year ended December 31, 2018, we incurred abandonment and impairment of unproved properties expense totaling $49.9 million. We incurred impairment of proved properties expense and abandonment and impairment of unproved properties expense totaling $3.8 million and $12.3 million, respectively, during 2017, and $354.6 million and $80.4 million, respectively, during 2016. 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 $1.0 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 $1.5 billion, up from $925.0 million at December 31, 2017. The next semi-annual redetermination date is scheduled for April 1, 2019. We do not expect a material change to the borrowing base or the aggregate lender commitments as a result of this redetermination. 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, 2018, we had the following outstanding long-term debt:

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

Additionally, we had no outstanding borrowings under our Credit Agreement as of December 31, 2018. We had one outstanding letter of credit in the aggregate amount of $200,000 (which reduces the amount available for borrowing under the facility on a dollar-for-dollar basis), resulting in $999.8 million of available borrowing capacity under our secured credit facility. Our long-term debt represented 47 percent of our total book capitalization as of December 31, 2018.

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 the Credit Agreement and the indentures governing our Senior Convertible Notes and our Senior 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 renewals of 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 the Credit Agreement and the indentures governing our Senior Convertible Notes and our Senior 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 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 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. The Company was in compliance with all financial and non-financial covenants as of December 31, 2018, and through the filing of this report.

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 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, 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. Our insurance 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.

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 the CERCLA or the Superfund law, the 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 in our Permian and South Texas & Gulf Coast regions 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, 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 Permian and South Texas & Gulf Coast regions. 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 will decide by March 2019 whether to initiate rulemaking governing the disposal of wastewater from oil and gas development. 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.

On March 26, 2015, the BLM published a final rule requiring, among other things, disclosure of chemicals used in hydraulic fracturing on federal and tribal lands, including private surface lands with underlying federal minerals. The rule was never implemented due to court challenges. On December 29, 2017, the BLM rescinded the rule. 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 greenhouse gas ("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 greenhouse gases 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.

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. A decision in the judicial challenge to the ozone standard is expected in 2019. 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 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 some 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 the Company can produce from the Company's wells or may limit the number of wells or the locations that the Company can drill.

In November 2016, the BLM finalized regulations to address methane emissions from oil and gas operations on federal and tribal lands. The regulations prohibit venting gas except in limited situations and limit the flaring of gas. 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.

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 “greenhouse gases” 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 greenhouse gases under existing provisions of the CAA. In particular, the EPA adopted two sets of rules regulating greenhouse gas emissions under the CAA. One rule requires a reduction in greenhouse gas emissions from motor vehicles, and the other regulates permitting and greenhouse gas 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 greenhouse gas permitting rules to the extent they impose a requirement to obtain a permit based solely on emissions of greenhouse gases. 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 greenhouse gases 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 greenhouse gases will be required to implement the best available capture technology for greenhouse gases. 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 greenhouse gas emissions from specified greenhouse gas 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 greenhouse gases 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 greenhouse gas 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 greenhouse gas 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 greenhouse gas 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 greenhouse gases 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 greenhouse gases, and almost one-half of the states have already taken measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas “cap and trade” programs. 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 greenhouse gas 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 greenhouse gas emissions and recently summarized the impact of imposition of a tax on greenhouse gas 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 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 greenhouse gas 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 greenhouse gases 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, 2018, to February 7, 2019, the intraday trading prices per share of our common stock as reported by the New York Stock Exchange ranged from a low of $13.15 per share in December 2018 to a high of $33.76 per share in October 2018. 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; and
- changes in the national and global economic outlook, including potential impacts from trade agreements.

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.

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. Thereafter, the Court stayed this matter pending the outcome of two appeals involving XTO Energy, Inc ("XTO"), before the Tenth Circuit Court of Appeals. After resolution of the XTO appeals, the stay was lifted in 2013.

The Company was originally the only named defendant, but, as a result of the Company's 2013 disposition of approximately 75% of its Oklahoma properties to various entities, with those entities agreeing to assume any liability for any past or present royalty claims, Plaintiff filed a Second Amended Complaint in 2014 joining such entities as defendants. Those defendants subsequently settled all claims with Plaintiff; however, that settlement was effectively stayed during extended appellate proceedings concerning disputed attorneys' fees in the matter. The Chieftain matter concerning the remaining Oklahoma properties was stayed during the fee dispute proceedings.

On August 2, 2018, the Court in this matter required that Plaintiff file any motion to certify a class by February 8, 2019. Plaintiff filed such motion but only with respect to royalty owners in wells attached 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.

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.

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, 2013, and ending on December 31, 2018, with the cumulative total returns of the Dow Jones U.S. Exploration and Production Index, and the Standard & Poor’s 500 Stock Index.

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 7, 2019, the number of record holders of our common stock was 65. Based upon inquiry, management believes that the number of beneficial owners of our common stock is approximately 21,337.

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, 2018, 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)
01/01/2018 - 03/31/2018	—	$ —	—	3,072,184
04/01/2018 - 06/30/2018	355	$ 26.64	—	3,072,184
07/01/2018 - 09/30/2018	115,429	$ 25.69	—	3,072,184
10/01/2018 - 12/31/2018	—	$ —	—	3,072,184
Total	115,784	$ 25.69	—	3,072,184

(1) All shares purchased by us in 2018 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,				
	2018	2017	2016	2015	2014
	(in millions, except per share data)				
Statement of operations data:					
Total operating revenues and other income	$2,067.1	$1,129.4	$1,217.5	$1,557.0	$2,522.3
Net income (loss)	$508.4	$(160.8)	$(757.7)	$(447.7)	$666.1
Net income (loss) per share:					
Basic	$4.54	$(1.44)	$(9.90)	$(6.61)	$9.91
Diluted	$4.48	$(1.44)	$(9.90)	$(6.61)	$9.79
Cash dividends declared and paid per common share	$0.10	$0.10	$0.10	$0.10	$0.10
Balance sheet data:					
Total assets	$6,352.9	$6,176.8	$6,393.5	$5,621.6	$6,483.1
Long-term debt:					
Revolving credit facility	$—	$—	$—	$202.0	$166.0
Senior Notes, net of unamortized deferred financing costs	$2,448.4	$2,769.7	$2,766.7	$2,316.0	$2,166.4
Senior Convertible Notes, net of unamortized discount and deferred financing costs	$147.9	$139.1	$130.9	$—	$—

Supplemental Selected Financial and Operations Data

	As of or for the Years Ended December 31,				
	2018	2017	2016	2015	2014
Balance sheet data (in millions):					
Total working capital (deficit)	$(36.8)	$(10.1)	$(190.5)	$216.5	$(39.6)
Total stockholders' equity	$2,920.3	$2,394.6	$2,497.1	$1,852.4	$2,286.7
Weighted-average common shares outstanding (in thousands):					
Basic	111,912	111,428	76,568	67,723	67,230
Diluted	113,502	111,428	76,568	67,723	68,044
Reserves:					
Oil (MMBbl)	175.7	158.2	104.9	145.3	169.7
Gas (Bcf)	1,321.8	1,280.1	1,111.1	1,264.0	1,466.5
NGLs (MMBbl)	107.4	96.5	105.7	115.4	133.5
MMBOE [(1)]	503.4	468.1	395.8	471.3	547.7
Production and operations (in millions):					
Oil, gas, and NGL production revenue	$1,636.4	$1,253.8	$1,178.4	$1,499.9	$2,481.5
Oil, gas, and NGL production expense	$487.4	$507.9	$597.6	$723.6	$715.9
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$665.3	$557.0	$790.7	$921.0	$767.5
General and administrative [(2)]	$116.5	$117.3	$124.8	$156.1	$166.5
Production volumes:					
Oil (MMBbl)	18.8	13.7	16.6	19.2	16.7
Gas (Bcf)	103.2	123.0	146.9	173.6	152.9
NGLs (MMBbl)	7.9	10.3	14.2	16.1	13.0
MMBOE [(1)]	43.9	44.5	55.3	64.2	55.1
Realized price, before the effect of derivative settlements:					
Oil (per Bbl)	$56.80	$47.88	$36.85	$41.49	$80.97
Gas (per Mcf)	$3.43	$3.00	$2.30	$2.57	$4.58
NGLs (per Bbl)	$27.22	$22.35	$16.16	$15.92	$33.34
Per BOE	$37.27	$28.20	$21.32	$23.36	$45.01
Expense per BOE:					
Lease operating expense	$4.74	$4.43	$3.51	$3.73	$4.28
Transportation costs	$4.36	$5.48	$6.16	$6.02	$6.11
Production taxes	$1.52	$1.18	$0.94	$1.13	$2.13
Ad valorem tax expense	$0.48	$0.34	$0.21	$0.39	$0.46
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$15.15	$12.53	$14.30	$14.34	$13.92
General and administrative [(2)]	$2.65	$2.64	$2.26	$2.43	$3.02
Statement of cash flows data (in millions):					
Provided by operating activities [(2)]	$720.6	$515.4	$552.8	$990.8	$1,456.6
Used in investing activities [(2)]	$(587.9)	$(201.5)	$(1,867.6)	$(1,144.6)	$(2,575.5)
Provided by (used in) financing activities [(2)]	$(368.7)	$(12.3)	$1,327.2	$153.7	$740.0

(1) Amounts may not calculate due to rounding.

(2) Certain prior period amounts have been reclassified to conform to the current period presentation on the consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 – Summary of Significant Accounting Policies of Part II, Item 8 for additional discussion of the change in presentation as a result

of adopting new accounting standards.

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

This discussion includes forward-looking statements. Please refer to Cautionary Information about Forward-Looking Statements in Part I, Items 1 and 2 of this report for important information about these types of statements.

Overview of the Company

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. We currently have producing assets and significant acreage positions in the Midland Basin and Eagle Ford shale in Texas. Our strategic objective is to be a premier operator of top tier assets. We seek to maximize the value of our assets by applying industry leading technology and outstanding operational execution. Our portfolio is comprised of unconventional resource prospects with expanding prospective drilling opportunities, which we believe provides for long-term production and reserves growth. We are focused on generating strong full-cycle economic returns on our investments and maintaining a strong balance sheet.

2018 Financial and Operational Highlights

Our objective to be a premier operator of top tier assets led to our multi-year portfolio transformation, which now allows us to focus solely on maximizing the value of our core acreage positions located in the Midland Basin and Eagle Ford shale. As part of our transformation strategy, we completed divestitures of substantially all remaining non-core assets in the first half of 2018. We used proceeds from these divestitures, along with operating cash flows, to fully fund our 2018 capital program and to meaningfully reduce our long-term debt. Additionally, we completed financial transactions during the year that extended the average maturity on our remaining long-term debt, and we had no outstanding borrowings against our credit facility as of December 31, 2018. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions and Note 5 – Long-Term Debt in Part II, Item 8 of this report for additional discussion.

Financial and Operational Results. During the year ended December 31, 2018, we achieved the following financial and operational results:

- Total estimated proved reserves increased eight percent from the prior year to 503.4 MMBOE as of December 31, 2018, of which 56 percent were liquids (oil and NGLs) and 49 percent were characterized as proved developed. During 2018, we added 188.0 MMBOE through our Midland Basin and Eagle Ford shale drilling programs as well as from changes to our future development strategy in the Eagle Ford shale, which includes wider spacing and longer lateral completions. These positive results for 2018 were partially offset by the divestiture of 40.3 MMBOE of estimated proved reserves, and net downward revisions of 68.8 MMBOE, which resulted primarily from changes in our development plans in our Eagle Ford shale program. On a retained asset basis, estimated proved reserves increased 18 percent year-over-year. Further, our estimated proved reserve life index increased to 11.5 years at December 31, 2018, compared to 10.5 years at December 31, 2017. 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 \$4.7 billion as of December 31, 2018, compared with \$3.0 billion as of December 31, 2017, which was an increase of 54 percent year-over-year. Please refer to Supplemental Oil and Gas Information in Part II, Item 8 of this report for additional discussion.
- Average net daily production for the year ended December 31, 2018, was 120.3 MBOE, compared with 121.8 MBOE for the same period in 2017. This decrease was driven largely by producing property divestitures in 2017 and in the first half of 2018. On a retained asset basis, production increased 11 percent year-over-year, which was due to a 91 percent increase in production volumes in our Permian region for the year ended December 31, 2018, compared with 2017. Please refer to A Year-to-Year Overview of Selected Production and Financial Information, Including Trends below for additional discussion on production.
- We recorded net income of \$508.4 million, or \$4.48 per diluted share, for the year ended December 31, 2018. This compares with a net loss of \$160.8 million, or \$1.44 per diluted share, for the year ended December 31, 2017. Please refer to Comparison of Financial Results and Trends Between 2018 and 2017 and Between 2017 and 2016 below for additional discussion regarding the components of net income (loss) for each period presented.
- Net cash provided by operating activities was \$720.6 million for the year ended December 31, 2018, compared with \$515.4 million for the year ended December 31, 2017, which was an increase of 40 percent year-over-year. The

increase in net cash provided by operating activities for 2018, compared with 2017, was primarily the result of 37 percent growth in higher margin oil production, which, combined with increased benchmark pricing for oil and NGLs, drove a 32 percent increase in our realized price per BOE before the effects of derivative settlements, and led to a 31 percent increase in oil, gas, and NGL production revenue. Partially offsetting the increase from oil, gas, and NGL production revenue was a cash settlement loss on derivatives of $135.8 million for the year ended December 31, 2018, compared to a cash settlement gain on derivatives of $21.2 million during 2017. Please refer to Analysis of Cash Flow Changes Between 2018 and 2017 and Between 2017 and 2016 below for additional discussion.

- Adjusted EBITDAX, a non-GAAP financial measure, for the year ended December 31, 2018, was $900.4 million, compared with $663.2 million for the same period in 2017. The increase in adjusted EBITDAX for 2018 was largely driven by the growth in higher margin oil production and improved benchmark pricing for oil and NGLs. This increase was partially offset by increased losses on derivative settlements. 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.

Long-Term Debt. During the year ended December 31, 2018, we executed certain long-term debt transactions and agreements, which are summarized below:

- 2021 Senior Notes Redemption. On July 16, 2018, we redeemed the $344.6 million principal outstanding of our 2021 Senior Notes using cash on hand resulting from property divestitures. Redemption of the 2021 Senior Notes resulted in a loss on extinguishment of debt of $9.8 million for the year ended December 31, 2018. This loss included $7.5 million associated with the premium paid and $2.3 million due to the acceleration of previously unamortized deferred financing costs.
- 2027 Senior Notes Issuance. On August 20, 2018, we issued $500.0 million in aggregate principal amount of 6.625% Senior Notes due 2027 and received net proceeds of $492.1 million. This offering was made in order to fund the tender offer and notes redemption discussed below.
- Tender Offer and Redemption of our 2023 Senior Notes and a Portion of our 2022 Senior Notes. Concurrently with our 2027 Senior Notes offering, we announced a cash tender offer (the “Tender Offer”), which included plans to redeem our 2023 Senior Notes and a portion of our 2022 Senior Notes. Upon completion of these transactions, we retired the $395.0 million principal outstanding of our 2023 Senior Notes and $85.0 million principal outstanding of our 2022 Senior Notes. We paid total consideration, including accrued interest, of $497.8 million to complete these transactions, which resulted in a loss on extinguishment of debt of $16.9 million for the year ended December 31, 2018. This amount included $12.9 million associated with premiums paid and $4.0 million due to the acceleration of previously unamortized deferred financing costs.
- Credit Agreement. On September 28, 2018, we entered into the Credit Agreement with our lenders which provides for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion, an initial borrowing base of $1.5 billion, and initial aggregate lender commitments totaling $1.0 billion. The Credit Agreement is scheduled to mature on September 28, 2023. The maturity date could, however, occur earlier on August 16, 2022, to the extent we have not completed certain repurchase, redemption, or refinancing activities associated with our 2022 Senior Notes as outlined in the Credit Agreement.

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

Operational Activities. The value 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 2018 due to the high percentage of oil these wells produce. Our operational execution and development strategy in this region has resulted in stronger well performance due to enhanced completion design 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 also increased in 2018, as a large portion of our water transportation and disposal needs are being satisfied by the water facilities we constructed 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.

In our Midland Basin program, we averaged seven drilling rigs and four completion crews during 2018, focusing on the development of the Lower Spraberry and Wolfcamp A and B shale intervals on our RockStar acreage in Howard and Martin Counties, Texas, as well as our Sweetie Peck acreage in Upton and Midland Counties, Texas. We completed 114 gross (104 net) operated wells during 2018 and increased production volumes year-over-year by 91 percent to 20.9 MMBOE, 79 percent of which was oil. 84 percent of our total 2018 drilling and completion capital was allocated to our Midland Basin program.

During 2018 in our operated Eagle Ford shale program, we were focused on increasing overall inventory value through optimizing our completion designs and by evaluating our development strategy and electing to revise our development plans to include wider spaced locations and longer lateral well completions that we believe will yield greater returns. We have also been active in assessing new intervals outside of the core Eagle Ford shale formation to further expand our future drilling inventory.

In September 2017, we entered into a joint venture agreement with a third-party to drill 16 wells and complete 23 wells in a focused portion of our Eagle Ford North area (“Phase 1 JV”). In December 2018, we extended this agreement and added an additional 12 wells to be drilled and completed (“Phase 2 JV”). The agreement provides that the third-party carries 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 allows 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 Phase 1 JV wells were drilled and completed as of December 31, 2018. Six of the 12 Phase 2 JV wells were drilled during 2018, and we expect the remaining six wells to be drilled and all 12 wells to be completed during 2019.
Our Eagle Ford shale program averaged one drilling rig and one completion crew during 2018. We completed 40 gross (26 net) wells during 2018. Total production for 2018 was 21.8 MMBOE, a 26 percent decrease from 2017. The decrease in production from our Eagle Ford shale program was primarily driven by the sale of our outside-operated assets in the first quarter of 2017 and reduced capital investment on our retained operated acreage. 14 percent of our total 2018 drilling and completion capital was allocated to our Eagle Ford shale program.

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, 2018.

	Permian		South Texas & Gulf Coast		Bakken/Three Forks [1]		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled but not completed at December 31, 2017	49	41	33	30	18	15	100	86
Wells drilled	126	117	36	20	—	—	162	137
Wells completed	(114)	(104)	(40)	(26)	—	—	(154)	(130)
Wells sold [1]	—	—	—	—	(18)	(15)	(18)	(15)
Other [2]	—	1	—	(1)	—	—	—	—
Wells drilled but not completed at December 31, 2018	61	55	29	23	—	—	90	78

(1) Drilled but not completed wells in this table relating to the Bakken/Three Forks operated program were included as part of the Divide County Divestiture, which was completed in the second quarter of 2018.
(2) Reflects net working interest changes resulting from normal business operations.

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, 2018
	(in millions)
Development costs	$ 1,147.6
Exploration costs	184.9
Acquisitions	
Proved properties	1.3
Unproved properties	55.7
Total, including asset retirement obligations [1]	$ 1,389.5

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

All of our development and exploration costs were incurred in our Midland Basin and Eagle Ford shale programs for the year ended December 31, 2018, with 84 percent of these costs being directed towards activities on our Midland Basin assets. Costs incurred for acquisitions during the year related to transactions in the Midland Basin, as well as payments made to extend certain lease terms, to acquire new leases, and to acquire certain surface rights associated with our Midland Basin water handling and transportation facilities. 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, 2018:

	Permian	South Texas & Gulf Coast	Rocky Mountain (1)	Total
Production:				
Oil (MMBbl)	16.6	1.3	0.9	18.8
Gas (Bcf)	25.8	76.2	1.2	103.2
NGLs (MMBbl)	—	7.9	—	7.9
Equivalent (MMBOE)	20.9	21.8	1.1	43.9
Avg. Daily Equivalents (MBOE/d)	57.4	59.9	3.1	120.3
Relative percentage	48 %	50 %	2 %	100 %

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 production on an equivalent basis for the year ended December 31, 2018, compared with 2017. The decrease in overall production volumes was primarily a result of the divestiture of our outside-operated Eagle Ford shale assets in the first quarter of 2017, decreased production from our operated Eagle Ford shale assets as a result of reduced capital investment, and the divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018. Production decreases from the Eagle Ford shale and Rocky Mountain region were mostly offset by the Permian region, which had an increase in production volumes of 91 percent for the year ended December 31, 2018, compared with 2017. Please refer to A Year-to-Year Overview of Selected Production and Financial Information, Including Trends and Comparison of Financial Results and Trends Between 2018 and 2017 and Between 2017 and 2016 below for additional discussion on production.

Divestiture Activity. On March 26, 2018, we divested approximately 112,000 net acres of our Powder River Basin assets for net divestiture proceeds of $492.2 million and recorded a final net gain of $410.6 million for the year ended December 31, 2018. During the second quarter of 2018, we divested our remaining assets in the Williston Basin, and our non-operated Halff East assets in the Midland Basin for combined net divestiture proceeds of $252.2 million. We recorded a combined final net gain of $15.4 million for the year ended December 31, 2018.

Acquisition Activity. During 2018, we acquired approximately 1,030 net acres of unproved properties in Howard and Martin Counties, Texas, in two separate transactions totaling $33.3 million. We also completed two non-monetary acreage trades of primarily unproved properties located in Howard and Martin Counties, Texas, resulting in the exchange of approximately 2,650 net acres, with $95.1 million of carrying value attributed to the properties we surrendered. These trades were recorded at carryover basis with no gain or loss recognized.

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, 2018, 2017, and 2016:

	For the Years Ended December 31,		
	2018	2017	2016
Oil (per Bbl):			
Average NYMEX contract monthly price	$64.77	$50.95	$43.32
Realized price, before the effect of derivative settlements	$56.80	$47.88	$36.85
Effect of oil derivative settlements	$(3.67)	$(2.28)	$14.63
Gas:			
Average NYMEX monthly settle price (per MMBtu)	$3.09	$3.11	$2.46
Realized price, before the effect of derivative settlements (per Mcf)	$3.43	$3.00	$2.30
Effect of gas derivative settlements (per Mcf)	$(0.12)	$0.72	$0.64
NGLs (per Bbl):			
Average OPIS price [(1)]	$32.96	$27.63	$19.98
Realized price, before the effect of derivative settlements	$27.22	$22.35	$16.16
Effect of NGL derivative settlements	$(6.78)	$(3.44)	$(0.60)

(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 prices for oil and NGLs to continue to be volatile. 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. We expect oil prices to remain volatile due to uncertainty in global supply and demand.

We expect gas prices to remain near current levels in the near term due to the abundance of supply relative to demand. Demand from increased liquefied natural gas ("LNG") exports and gas exports to Mexico are expected to help balance supply.

We expect NGL prices to continue to benefit from increased demand from export and petrochemical markets while being offset by increased drilling activity.

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 7, 2019, and December 31, 2018:

	As of February 7, 2019	As of December 31, 2018
NYMEX WTI oil (per Bbl)	$ 54.48	$ 46.96
NYMEX Henry Hub gas (per MMBtu)	$ 2.75	$ 2.85
OPIS NGLs (per Bbl)	$ 25.11	$ 24.04

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. 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 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

We remain focused on maximizing the returns and increasing the value of our top tier capital project inventory in the Midland Basin and Eagle Ford shale. We expect to do this through exploration, acquisitions, and further development optimization. These assets will allow for production growth while maximizing internally generated cash flows, which will also support our priorities for improving our credit metrics and maintaining strong financial flexibility.

Our capital program for 2019, excluding acquisitions, is expected to range from $1.00 billion to $1.07 billion. We expect our capital program to concentrate on developing our top tier assets in the Midland Basin and Eagle Ford shale. We expect to allocate approximately 80% of our 2019 capital to our Midland Basin program, which generates the highest margins in our portfolio. Planned drilling and completion activity in the Eagle Ford shale will be partially funded by a third-party as part of our joint venture agreement. By concentrating our capital on high return investments and operating at strong performance levels, we believe we will generate higher company-wide margins, cash flow growth, and value creation for our stockholders.

In our Permian region, we entered 2019 with six drilling rigs and three completion crews and anticipate maintaining this level of activity on average throughout the remainder of the year. On our operated acreage, we plan to drill and complete approximately 100 net wells in 2019. Our focus will continue to be on delineating and developing the Lower Spraberry and Wolfcamp A and B shale intervals on our RockStar acreage in Howard and Martin Counties, Texas, and our Sweetie Peck acreage in Upton and Midland Counties, Texas.

In our South Texas & Gulf Coast region, we entered 2019 with one drilling rig and added one completion crew in January. We anticipate averaging one to two drilling rigs and one completion crew throughout 2019. We plan to drill approximately 28 net wells and plan to complete approximately 18 net wells in 2019. We expect our joint venture in a portion of our Eagle Ford North area will allow for an increase in our capital efficiency. This joint venture will continue to test new technologies and completion designs at varied well spacing, potentially enhancing the asset's value while reducing the required capital outlay that is necessary to meet certain lease obligations.

Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our 2019 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, 2018, and the immediately preceding three quarters.

	For the Three Months Ended			
	December 31, 2018	September 30, 2018	June 30, 2018	March 31, 2018
	(in millions)			
Production (MMBOE)	11.3	12.0	10.5	10.1
Oil, gas, and NGL production revenue	$392.5	$458.4	$402.6	$382.9
Oil, gas, and NGL production expense	$121.5	$127.6	$117.4	$120.9
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$182.0	$201.1	$151.8	$130.5
Exploration	$14.3	$13.1	$14.1	$13.7
General and administrative	$30.4	$29.5	$28.9	$27.7
Net income (loss)	$309.7	$(135.9)	$17.2	$317.4

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics

	For the Three Months Ended			
	December 31, 2018	September 30, 2018	June 30, 2018	March 31, 2018
Average net daily production equivalent (MBOE per day)	122.8	130.2	115.2	112.7
Lease operating expense (per BOE)	$4.98	$4.41	$4.66	$4.95
Transportation costs (per BOE)	$4.19	$4.20	$4.47	$4.63
Production taxes as a percent of oil, gas, and NGL production revenue	3.4 %	4.1 %	4.3 %	4.4 %
Ad valorem tax expense (per BOE)	$0.39	$0.45	$0.41	$0.67
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$16.10	$16.78	$14.48	$12.87
General and administrative (per BOE)	$2.69	$2.46	$2.76	$2.73

Note: Amounts may not calculate due to rounding.

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	
	2018	2017	2016	2018/2017	2017/2016	2018/2017	2017/2016
Net production volumes: [1]							
Oil (MMBbl)	18.8	13.7	16.6	5.1	(2.9)	37 %	(18)%
Gas (Bcf)	103.2	123.0	146.9	(19.8)	(23.9)	(16)%	(16)%
NGLs (MMBbl)	7.9	10.3	14.2	(2.4)	(3.9)	(23)%	(27)%
Equivalent (MMBOE)	43.9	44.5	55.3	(0.6)	(10.8)	(1)%	(20)%
Average net daily production: [1]							
Oil (MBbl per day)	51.4	37.4	45.4	14.0	(7.9)	37 %	(17)%
Gas (MMcf per day)	282.7	337.0	401.5	(54.3)	(64.5)	(16)%	(16)%
NGLs (MBbl per day)	21.8	28.2	38.8	(6.4)	(10.6)	(23)%	(27)%
Equivalent (MBOE per day)	120.3	121.8	151.0	(1.5)	(29.2)	(1)%	(19)%
Oil, gas, and NGL production revenue (in millions): [1]							
Oil production revenue	$1,065.7	$654.3	$611.8	$411.4	$ 42.5	63 %	7 %
Gas production revenue	354.5	369.4	337.3	(15.0)	32.1	(4)%	10 %
NGL production revenue	216.2	230.1	229.3	(13.9)	0.8	(6)%	— %

Total oil, gas, and NGL production revenue	$1,636.4	$1,253.8	$1,178.4	$382.6	$ 75.4	31 %	6 %
Oil, gas, and NGL production expense (in millions): (1)							
Lease operating expense	$208.1	$196.9	$194.0	$11.2	$ 2.9	6 %	1 %
Transportation costs	191.5	243.6	340.3	(52.1)	(96.7)	(21)%	(28)%
Production taxes	66.9	52.4	51.9	14.5	0.5	28 %	1 %
Ad valorem tax expense	20.9	15.0	11.4	5.9	3.6	39 %	32 %
Total oil, gas, and NGL production expense	$487.4	$507.9	$597.6	$(20.5)	$ (89.7)	(4)%	(15)%
Realized price, before the effect of derivative settlements:							
Oil (per Bbl)	$56.80	$47.88	$36.85	$8.92	$ 11.03	19 %	30 %
Gas (per Mcf)	$3.43	$3.00	$2.30	$0.43	$ 0.70	14 %	30 %
NGLs (per Bbl)	$27.22	$22.35	$16.16	$4.87	$ 6.19	22 %	38 %
Per BOE	$37.27	$28.20	$21.32	$9.07	$ 6.88	32 %	32 %
Per BOE data:							
Production costs:							

Lease operating expense	$4.74	$4.43	$3.51	$0.31	$ 0.92	7 %	26 %
Transportation costs	$4.36	$5.48	$6.16	$(1.12)	$ (0.68)	(20)%	(11)%
Production taxes	$1.52	$1.18	$0.94	$0.34	$ 0.24	29 %	26 %
Ad valorem tax expense	$0.48	$0.34	$0.21	$0.14	$ 0.13	41 %	62 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$15.15	$12.53	$14.30	$2.62	$ (1.77)	21 %	(12)%
General and administrative [2]	$2.65	$2.64	$2.26	$0.01	$ 0.38	— %	17 %
Derivative settlement gain (loss) [3]	$(3.09)	$0.48	$5.96	$(3.57)	$ (5.48)	(744)%	(92)%
Earnings per share information:							
Basic weighted-average common shares outstanding (in thousands)	111,912	111,428	76,568	484	34,860	— %	46 %
Diluted weighted-average common shares outstanding (in thousands)	113,502	111,428	76,568	2,074	34,860	2 %	46 %
Basic net income (loss)	$4.54	$(1.44)	$(9.90)	$5.98	$ 8.46	415 %	85 %

per common share							
Diluted net income (loss) per common share	$14.48	$(1.44)	$(9.90)	$5.92	$8.46	411 %	85 %

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

(2) Prior periods have been adjusted to conform to the current period presentation on the consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 – Summary of Significant Accounting Policies in Part II, Item 8 of this report for additional discussion.

(3) Derivative settlements for the years ended December 31, 2018, 2017, and 2016, are included within the net derivative (gain) loss line item in the accompanying statements of operations.

Average net equivalent daily production for the year ended December 31, 2018, decreased one percent compared with 2017. This decrease is primarily due to the divestiture of our outside-operated Eagle Ford shale assets in the first quarter of 2017, the divestiture of our remaining producing assets in the Rocky Mountain region in the first half of 2018, and decreasing production due to reduced capital investment in our operated Eagle Ford shale assets. Production decreases in the Eagle Ford shale and Rocky Mountain region were substantially offset by our Permian region, which had a 91 percent increase in production volumes for the year ended December 31, 2018, compared with 2017. We anticipate 2019 total production to be higher than 2018 total production, driven by continued development of our Permian assets in the Midland Basin. Please refer to Comparison of Financial Results and Trends Between 2018 and 2017 and Between 2017 and 2016 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.

Changes in production volumes, revenues, and costs are directly influenced by the volatility of commodity prices for the products we produce, fluctuations in costs necessary to develop and operate our properties, our ability to increase efficiencies in operations, and changes in our overall asset portfolio. Our realized price before the effect of derivative settlements on a per BOE basis for the year ended December 31, 2018, increased 32 percent compared with 2017, which was driven primarily by a 37 percent growth in higher margin oil production and improved benchmark pricing for oil and NGLs. For the year ended December 31, 2018, we realized a loss of $3.09 per BOE on the settlement of our derivative contracts, which was primarily driven by improving oil and NGL prices in 2018, compared to a gain of $0.48 per BOE in 2017. Settlement losses due to strengthening commodity prices in 2018 were partially offset by cash settlement gains on our Midland Basin oil basis swaps that settled during 2018. Overall, there was a 19 percent increase in our realized price after the effect of derivative settlements for the year ended December 31, 2018, compared with 2017.

Lease operating expense (“LOE”) increased seven percent on a per BOE basis for the year ended December 31, 2018, compared with 2017. This increase was primarily driven by the increased percentage of oil in our total product mix, which has higher lifting costs per BOE. We expect LOE on a per BOE basis to be flat or slightly higher in 2019 compared with 2018 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, changes in our overall production mix, timing of workover projects, and changes in industry activity and the effects this has on service provider costs.

Transportation costs decreased 20 percent on a per BOE basis for the year ended December 31, 2018, compared with 2017. The decrease in transportation costs per BOE continues to be driven by production decreases from our Eagle Ford shale assets, which have higher average transportation costs. Our Permian region production is primarily sold at the wellhead and therefore is subject to minimal transportation costs. We expect total transportation costs to fluctuate in line with changes in production from our operated Eagle Ford shale program as these assets incur the majority of our transportation costs. On a per BOE basis, we expect transportation costs to decrease in 2019, as compared with 2018, 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, 2018, increased 29 percent compared with 2017, primarily due to a 32 percent increase in our realized price on a per BOE basis before the effect of derivative settlements for the year ended December 31, 2018, compared with 2017. Our overall production tax rate for the years ended December 31, 2018, and 2017 was 4.1 percent and 4.2 percent, respectively. The slight decrease in our production tax rate was primarily a result of divesting our remaining producing assets in the Rocky Mountain region, which were taxed at higher rates than our Texas properties. We generally expect production tax expense to trend with oil, gas, and NGL production revenue on an absolute and per BOE basis. We expect our overall production tax expense to remain consistent in 2019 compared to 2018, as the impacts of expected higher production volumes are

expected to be offset by lower commodity prices, assuming such prices are consistent with the 12-month strip pricing as of February 7, 2019, as presented above within the Oil, Gas, and NGL Prices section. We expect our overall production tax rate to remain consistent in 2019 compared to 2018. 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, 2018, increased 41 percent compared with 2017, due to changes in our asset and production base and increased commodity price assumptions used in 2018 property tax valuations. The majority of ad valorem tax expense is related to our Texas properties. We expect an overall increase in the value attributed to our reserves volumes in 2019, which would increase ad valorem tax on an absolute basis compared with 2018. On a per BOE basis, we expect 2019 ad valorem expense to also increase compared to 2018, but this increase could be partially offset by expected increases in production volumes in 2019 compared with the prior year.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion (“DD&A”) expense on a per BOE basis increased 21 percent for the year ended December 31, 2018, compared with 2017. The increase was primarily driven by the increase in production volumes from our Midland Basin assets, which have higher depletion rates than our Eagle Ford shale assets. DD&A was also higher as a result of the capital we invested in 2018 to construct our water transportation facilities in the Midland Basin. 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 2019 to increase compared with 2018 as production from our Midland Basin program continues to increase as a percentage of our total production.

General and administrative (“G&A”) expense remained flat on a per BOE basis for the year ended December 31, 2018, compared with 2017. We expect G&A expense on a per BOE basis in 2019 to decrease slightly compared with 2018, as total production in 2019 is expected to increase from total 2018 production.

Please refer to Comparison of Financial Results and Trends Between 2018 and 2017 and Between 2017 and 2016 for additional discussion.

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. 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. We recorded a net loss for the years ended December 31, 2017, and 2016. 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, 2017, and 2016.

Comparison of Financial Results and Trends Between 2018 and 2017 and Between 2017 and 2016

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, 2018, and 2017:

	Net Equivalent Production Increase (Decrease) (MBOE per day)	Production Revenue Increase (Decrease) (in millions)	Production Expense Increase (Decrease) (in millions)
Permian	27.4	$ 582.5	$ 89.5
South Texas & Gulf Coast	(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 Eagle Ford shale and Rocky Mountain region were predominately offset by the 91 percent production volume increase in our Permian region for the year ended December 31, 2018, compared with 2017. Increased production in the Permian region 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 to the prior year. 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.

The following table presents the regional changes in our net equivalent production, production revenue, and production expense between the years ended December 31, 2017, and 2016:

	Net Equivalent Production Increase (Decrease) (MBOE per day)	Production Revenue Increase (Decrease) (in millions)	Production Expense Increase (Decrease) (in millions)
Permian	19.8	$ 347.3	$ 76.5
South Texas & Gulf Coast	(31.9)	(113.5)	(92.5)
Rocky Mountain	(17.1)	(158.4)	(73.7)
Total	(29.2)	$ 75.4	$ (89.7)

Note: Amounts may not calculate due to rounding.

Oil, gas, and NGL production revenue increased six percent in 2017 compared with 2016 as the 32 percent increase in realized price, before the effects of derivative settlements, on a per BOE basis was mostly offset by the 20 percent decrease in net equivalent production volumes as a result of divestiture activity. 2017 production expense decreased $89.7 million when compared with 2016 due to a 20 percent decrease in net equivalent production volumes. The 15 percent decrease in production expense was less than the 20 percent decrease in net equivalent production volumes, which resulted in increased production expense per BOE. On a per BOE basis, production expense increased slightly in 2017 compared with 2016 primarily due to the sale of our outside-operated Eagle Ford shale assets in the first quarter of 2017, which had lower average lifting costs per BOE than our retained assets.

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, 2018, 2017, and 2016.

Net gain (loss) on divestiture activity

	For the Years Ended December 31,		
	2018	2017	2016
	(in millions)		
Net gain (loss) on divestiture activity	$426.9	$(131.0)	$37.1

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 PRB Divestiture, which closed in the first quarter of 2018, and a combined total net gain of $15.4 million recorded for the Divide County Divestiture and the Halff East Divestiture, both of 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 previously held for sale. 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.

The net gain on divestiture activity recorded for the year ended December 31, 2016, was primarily the result of the $29.5 million net gain recorded on our Raven/Bear Den assets sold in the fourth quarter of 2016, as well as a $6.3 million total net gain recorded on the non-core Williston Basin, Powder River Basin, and southeast New Mexico asset divestitures in the third quarter of 2016.

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,		
2018	2017	2016
(in millions)		

Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$665.3	$557.0	$790.7

DD&A expense for the year ended December 31, 2018, increased 19 percent compared with 2017. The increase is directly related to the 91 percent increase in production volumes from our Midland Basin assets in the Permian region, which have higher depletion rates than our Eagle Ford shale assets in the South Texas & Gulf Coast region.

DD&A expense for the year ended December 31, 2017, decreased 30 percent compared with 2016 due to a 20 percent decrease in production volumes and the impact of assets sold or classified as held for sale throughout 2017.
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,		
	2018	2017	2016
	(in millions)		
Geological and geophysical expenses	$5.6	$4.0	$11.0
Exploratory dry hole	—	2.4	—
Overhead and other expenses [1]	49.6	48.3	54.0
Total [1]	$55.2	$54.7	$65.0

(1) Prior periods have been adjusted to conform to the current period presentation on the consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 – Summary of Significant Accounting Policies in Part II, Item 8 of this report for additional discussion.

Exploration expense increased one percent for the year ended December 31, 2018, compared with 2017. In 2019, we expect to continue focusing on testing and delineating our Midland Basin acreage, which may result in additional geological and geophysical expenses; however, we do not expect total exploration activity and related expenses to differ significantly compared with 2018. Our expectations for exploration expense could change significantly depending on actual geological and geophysical studies we perform, the amount of allocated overhead, and the potential for exploratory dry hole expense.
Exploration expense for the year ended December 31, 2017, decreased 16 percent compared with 2016 driven primarily by geological and geophysical expenses incurred for a seismic study performed on our Midland Basin acreage in the fourth quarter of 2016, which were not incurred in 2017.
Impairment of proved properties and Abandonment and impairment of unproved properties

	For the Years Ended December 31,		
	2018	2017	2016
	(in millions)		
Impairment of proved properties	$—	$3.8	$354.6
Abandonment and impairment of unproved properties	$49.9	$12.3	$80.4

There was no impairment of proved properties expense recognized for the year ended December 31, 2018. Unproved property abandonments and impairments recorded for the year ended December 31, 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 more likely occur in periods of declining or depressed commodity prices, and unproved property impairments to fluctuate with the timing of lease expirations or defects, unsuccessful exploration activities, and changing economics associated with decreases in commodity prices. Additionally, changes in drilling plans, downward engineering revisions, or unsuccessful exploration efforts 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 7, 2019, we do not expect any material impairments in the first quarter of 2019 resulting from commodity price impacts. Please refer to Critical Accounting Policies and Estimates below for additional discussion.
There was no material impairment of proved properties recognized for the year ended December 31, 2017. Abandonment and impairment of unproved properties expense recorded during the year ended December 31, 2017, related primarily to lease expirations.
The majority of our proved property impairments during 2016 were recorded in the first quarter of 2016 in our outside-operated Eagle Ford shale program as a result of commodity price declines. In the fourth quarter of 2016, we

recorded proved and unproved property impairment expense on our Powder River Basin assets as a result of negative performance reserve revisions at year end 2016 and lower market prices on third-party acreage transactions. Additionally, we allowed certain leases to expire throughout the year ended December 31, 2016.

General and administrative

	For the Years Ended December 31,		
	2018	2017	2016
	(in millions)		
General and administrative [1]	$116.5	$117.3	$124.8

(1) Prior periods have been adjusted to conform to the current period presentation on the consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 – Summary of Significant Accounting Policies in Part II, Item 8 of this report for additional discussion.

G&A expense for the year ended December 31, 2018, was flat compared with 2017. We expect G&A expense in total to continue to remain relatively flat in 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 costs on a per BOE basis.

G&A expense for the year ended December 31, 2017, decreased six percent from 2016 primarily due to decreased compensation expense resulting from lower average headcount for the full year in 2017.

Net derivative (gain) loss

	For the Years Ended December 31,		
	2018	2017	2016
	(in millions)		
Net derivative (gain) loss	$(161.8)	$26.4	$250.6

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. Additionally, we recorded 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.

We recognized a net derivative loss of $250.6 million for the year ended December 31, 2016. For contracts that settled during 2016, the fair value was a net asset of $367.7 million at December 31, 2015, and net cash settlements received totaled $329.5 million, resulting in a $38.2 million loss. Additionally, we recorded a $212.4 million mark-to-market loss on remaining contracts as of December 31, 2016, 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,		
	2018	2017	2016
	(in millions)		
Interest expense	$(160.9)	$(179.3)	$(158.7)

The $18.4 million, or 10 percent, decrease in interest expense for the year ended December 31, 2018, compared with the same period in 2017, was driven in part by the redemption of our 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. As a result of our overall reduction in long-term debt, we expect interest expense related to our Senior Notes to be lower in 2019 compared with 2018; however, total interest expense

can vary based on the timing and amount of any borrowings against our credit facility.
The $20.6 million, or 13 percent, increase in interest expense for the year ended December 31, 2017, compared with 2016, was driven by an increase in total debt outstanding for full year 2017 due to additional debt issuances in the second half of 2016. Offsetting a portion of the increase was additional interest expense of $10.0 million recognized in 2016 as a result of terminating an unused second lien facility that was no longer necessary to fund a portion of our Midland Basin acquisitions.

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.

Gain (loss) on extinguishment of debt

	For the Years Ended December 31,		
	2018	2017	2016
	(in millions)		
Gain (loss) on extinguishment of debt	$(26.7)	$ —	$15.7

For the year ended December 31, 2018, we recorded a $26.7 million net loss on the early extinguishment of our 2021 Senior Notes, 2023 Senior Notes, and a portion of our 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.

For the year ended December 31, 2016, we recorded a $15.7 million net gain on the early extinguishment of a portion of our Senior Notes, which included $16.4 million associated with the discount realized upon repurchase, slightly offset by $700,000 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,		
	2018	2017	2016
	(in millions, except tax rate)		
Income tax (expense) benefit	$(143.4)	$183.0	$444.2
Effective tax rate	22.0 %	53.2 %	37.0 %

The decrease in the effective tax rate for 2018 compared with 2017 is primarily due to the impacts of the Tax Cuts and Jobs Act (the “2017 Tax Act”). The 18.5 percentage point increase in 2017 from a nonrecurring deferred tax adjustment was caused by the 14 percentage point 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 percentage point 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 settlement of employee share-based payment 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.

The increase in the effective tax rate in 2017 compared with 2016 was primarily due to the enactment of the 2017 Tax Act into law on December 22, 2017, which decreased the highest marginal corporate tax rate and resulted in an 18.5 percentage point nonrecurring benefit adjustment increasing the effective tax rate. This increase was partially offset by an excess tax deficiency from the settlement of employee share-based payment awards, state apportionment changes due to the sale of our outside-operated Eagle Ford shale assets, and a net decrease in valuation allowances due to projected utilization of various state net operating losses.

Please refer to Overview of Liquidity and Capital Resources and Critical Accounting Policies and Estimates below as well as Note 4 – Income Taxes in 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 to maintain the flexibility to adjust our activity and capital expenditures.

Sources of Cash

We currently expect our 2019 capital program to be funded by cash flows from operations, cash proceeds from prior divestiture activities, and with any remaining cash needs being funded by borrowings under our credit facility. During the year ended December 31, 2018, we generated $720.6 million of cash flows from operating activities and we received $748.5 million of net proceeds from the sale of oil and gas properties. As of December 31, 2018, the combination of our cash balance of $78.0 million with our $1.0 billion of available borrowing capacity under our Credit Agreement provided $1.1 billion in liquidity. Although we anticipate cash flows from these sources will be sufficient to fund our expected 2019 capital program, we may also elect to raise funds through debt or equity financings or from other sources. Further, we may enter into additional carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. Our borrowing base could be reduced as a result of lower commodity prices, divestitures of proved properties, or the issuance of debt securities. 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. Any future downgrades in our credit ratings could make it more difficult or expensive for us to borrow additional funds. All of our sources of liquidity can be affected by the general condition of the broader economy and by 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 federal tax rate for 2018 and future years from 35 percent to 21 percent. It also eliminated the domestic production activities deduction for all taxpayers, the alternative minimum tax (“AMT”) for corporate taxpayers, and may impact our ability to deduct interest expense in future years. However, it did not impact current tax deductions for intangible drilling costs, percentage depletion, or amortization of geological and geophysical expenses, and it will allow us the option to expense 100 percent of our equipment acquisition costs in future years. In general, we believe the enactment of the 2017 Tax Act will have a positive impact on our future operating cash flows.

Credit Agreement

On September 28, 2018, we entered into the Sixth Amended and Restated Credit Agreement with our lenders. The Credit Agreement, which replaced our Fifth Amended and Restated Credit Agreement, provides for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion, an initial borrowing base of $1.5 billion, and initial aggregate lender commitments totaling $1.0 billion. The Credit Agreement 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. We had no outstanding balance under our Credit Agreement as of December 31, 2018, or 2017. 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 7, 2019, December 31, 2018, and December 31, 2017.

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. We do not expect a material change to the borrowing base or the aggregate lender commitments during the next scheduled redetermination on April 1, 2019.

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. The 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. We were in compliance with all financial and non-financial covenants as of December 31, 2018, and through the filing of this report. Please refer to the caption Non-GAAP Financial Measures below for the calculation of adjusted EBITDAX and reconciliations of net income (loss) and net cash provided by operating activities to adjusted EBITDAX.

We had no credit facility borrowing activity during 2018. This was a result of our cash balance entering 2018 and cash proceeds received during 2018 from the PRB Divestiture, Divide County Divestiture, and Halff East Divestiture. Our daily weighted-average credit facility debt balance was approximately $13.1 million and $183.8 million for the years ended December 31, 2017, and 2016, respectively. 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.

Weighted-Average Interest 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, 2018, 2017, and 2016.

	For the Years Ended December 31,		
	2018	2017	2016
Weighted-average interest rate	6.4%	6.4%	6.2%
Weighted-average borrowing rate	5.8%	5.8%	5.7%

Our weighted-average interest rates and weighted average borrowing rates for the years ended December 31, 2018, 2017, and 2016, have been impacted by the timing of long-term debt issuances and redemptions, the average balance on our revolving credit facility under the Credit Agreement, and the fees paid on the unused portion of our aggregate commitment. There was no change in our weighted-average interest rate or weighted-average borrowing rate for the years ended December 31, 2018, and 2017. The increase in these rates for the year ended 2017, as compared with 2016, was largely due to the issuance of the Senior Convertible Notes and the 2026 Senior Notes in the third quarter of 2016. 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. The rates also do not reflect the $10.0 million fee paid to terminate an unused second lien facility in the third quarter of 2016. 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 acquisition, exploration, and development 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 acquisition, exploration, and development of oil and gas properties are the primary use of our capital resources. During 2018, we spent approximately $1.3 billion on capital expenditures and on acquisitions, which were comprised primarily of unproved oil and gas properties. This amount differs from the costs incurred amount, which is accrual-based and includes asset retirement obligations, geological and geophysical expenses, and exploration overhead amounts.

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 drilling 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 certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges 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 exchanges are reviewed as part of the allocation of our capital. On July 16, 2018, we completed the 2021 Senior Notes Redemption which resulted in the payment of total cash consideration, including accrued interest, of $355.9 million. On August 20, 2018, we issued $500.0 million in aggregate principal amount of 2027 Senior Notes which resulted in the receipt of 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. The proceeds received from the issuance of the 2027 Senior Notes were used to complete the Tender Offer and 2023 Senior Notes Redemption. As a result, we repurchased our 2023 Senior Notes and a portion of our 2022 Senior Notes during the third quarter of 2018, which resulted in the payment of total consideration, including accrued interest, of $497.8 million. 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 2019, we will continue to focus on improving our debt metrics and potentially reducing 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 2018, 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 2019.

During 2018, we paid $11.2 million in dividends to our stockholders, reflecting a dividend of $0.10 per share. 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 Convertible Notes and Senior 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 2018 and 2017 and Between 2017 and 2016

The following tables present changes in cash flows between the years ended December 31, 2018, 2017, and 2016, for our operating, investing, and financing activities. The year ended December 31, 2016, has been adjusted to conform to the current period presentation on the consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 – Summary of Significant Accounting Policies in Part II, Item 8 of this report for additional discussion of adjustments made as a result of adopting new accounting standards. 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		Percent Change Between	
	2018	2017	2016	2018/2017	2017/2016	2018/2017	2017/2016
	(in millions)						
Net cash provided by operating activities	$720.6	$515.4	$552.8	$205.2	$ (37.4)	40%	(7)%

Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, increased $196.0 million, or 19 percent, to $1.2 billion for the year ended December 31, 2018, compared with the same period in 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 the same period in 2017, due to the redemption and repurchase of 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.

Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, decreased $91.6 million, or eight percent, to $1.0 billion for the year ended December 31, 2017, compared with the same period in 2016, as a result of a 20 percent decrease in production volumes partially offset by an increase in our realized price after the effect of derivative settlements. Interest paid increased $34.3 million for the year ended December 31, 2017, compared with the same period in 2016, due to the issuance of our 2026 Senior Notes and Senior Convertible Notes in the third quarter of 2016. Cash paid for LOE and ad valorem taxes in 2017 decreased $19.7 million, or nine percent, to $199.1 million compared with 2016, as a result of a 20 percent decrease in production volumes partially offset by an increase in production costs on a per BOE basis, specifically LOE, production taxes, and ad valorem taxes. Cash paid for G&A expense decreased $13.8 million, or 12 percent, to $98.6 million in 2017 compared with 2016, primarily as a result of the decrease in average headcount for 2017. During 2016, we paid $10.0 million to terminate a second lien facility that was not needed to fund the Rock Oil Acquisition. Further, net cash provided by operating activities is affected by working capital changes.

Investing Activities

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2018	2017	2016	2018/2017	2017/2016	2018/2017	2017/2016
	(in millions)						

Net cash used in investing activities	$(587.9)	$(201.5)	$(1,867.6)	$(386.4)	$ 1,666.1	192%	(89)%

Net cash used in investing activities increased for the year ended December 31, 2018, compared with the same period in 2017. Capital expenditures in 2018 increased $414.8 million, or 47 percent, compared with 2017 as a result of increased drilling and

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completion activities. During 2018, cash paid to acquire proved and unproved properties decreased $56.6 million, or 63 percent compared with 2017. Further, net proceeds from the sale of oil and gas properties decreased $28.2 million for 2018, compared with the same period in 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.

Net cash used in investing activities decreased for the year ended December 31, 2017, compared with the same period in 2016. During 2017, cash paid to acquire proved and unproved properties in the Midland Basin totaled $89.9 million compared with $2.2 billion paid in 2016. Net proceeds from the sale of oil and gas properties decreased $169.3 million for the year ended December 31, 2017, compared with the same period in 2016. During 2017, net proceeds were primarily from the sale of our outside-operated Eagle Ford shale assets, and during 2016, net proceeds were primarily related to the divestitures of our Raven/Bear Den and certain other non-core Permian and Rocky Mountain assets. Capital expenditures in 2017 increased $258.4 million, or 41 percent, compared with 2016 as a result of increased drilling and completion activities and slightly higher service provider costs.

In 2017, we adjusted year ended December 31, 2016, amounts to conform to the current period presentation on the consolidated financial statements. As a result, we reclassified $3.0 million of restricted cash out of investing activities and combined it with cash and cash equivalents when reconciling the beginning and end of period balances on the accompanying statements of cash flows, resulting in a decrease in net cash used in investing activities in 2016. Please refer to Recently Issued Accounting Standards in Note 1 – Summary of Significant Accounting Policies of Part II, Item 8 for additional discussion of adjustments made as a result of adopting new accounting standards.

Financing Activities

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2018	2017	2016	2018/2017	2017/2016	2018/2017	2017/2016
	(in millions)						
Net cash provided by (used in) financing activities	$(368.7)	$(12.3)	$1,327.2	$(356.4)	$(1,339.5)	2,898%	(101)%

Net cash used in financing activities increased for the year ended December 31, 2018, compared with the same period in 2017 primarily as a result of the redemption of $344.6 million principal outstanding of our 2021 Senior Notes. Cash flows related to financing activities during 2018 were also impacted by the repurchase of $395.0 million principal outstanding of our 2023 Senior Notes and $85.0 million principal outstanding of our 2022 Senior Notes. Premiums totaling $20.4 million were also paid in connection with these redemptions and repurchases during 2018. Offsetting these cash outflows, was cash provided by the issuance of our 2027 Senior Notes in 2018 for net proceeds of $492.1 million. Dividend payments during the years ended December 31, 2018 and 2017, were $11.2 million and $11.1 million, respectively. We had a zero balance on our credit facility as of December 31, 2018 and 2017, due to our cash balance resulting from the proceeds received from the PRB Divestiture, Divide County Divestiture, and Halff East Divestiture in the first half of 2018, proceeds received from the sale of our outside-operated Eagle Ford shale assets during 2017, and proceeds received from the sale of our Raven/Bear Den assets in December 2016. Consequently, there was no credit facility activity during 2018, and credit facility borrowings and repayments netted to zero in 2017. During 2016, we received $934.1 million of net proceeds from two public equity offerings, $491.6 million of net proceeds from our 2026 Senior Notes issuance, and $166.6 million of net proceeds from our Senior Convertible Notes issuance. These proceeds were used to partially fund the Rock Oil Acquisition and QStar Acquisition, as well as repay our credit facility balance of $202.0 million during the year ended December 31, 2016. Additionally, in 2016, we paid $24.2 million for capped call transactions related to our Senior Convertible Notes and paid $29.9 million for the repurchase of $46.3 million in aggregate principal amount of a portion of our senior notes. Please refer to Note 5 – Long-Term Debt and Note 13 – Equity 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, 2018, we had a zero 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 market 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 market 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 market values. As of December 31, 2018, our outstanding principal amount of fixed-rate debt totaled $2.6 billion. 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, overall profitability, access to capital, and future rate of growth. Oil, gas, and NGL prices are subject to wide fluctuations in response to changes in supply and demand and other factors. 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 prices we receive for our production depend on numerous factors beyond our control. Based on our 2018 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 $106.6 million, $35.4 million, and $21.6 million, respectively. If commodity prices had been 10 percent lower, our net derivative settlements for the year ended December 31, 2018 would have offset the declines in oil, gas, and NGL production revenue by approximately $117.8 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, 2018, 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 liability positions by approximately $71.8 million, $23.9 million, and $12.9 million, respectively.

Schedule of Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2018, 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)	$2,649.3	$—	$172.5	$476.8	$2,000.0
Interest payments (2)	970.4	155.5	309.8	272.1	233.0
Delivery commitments (3)	287.8	40.3	150.8	88.2	8.5
Operating leases and contracts (3)	169.7	92.2	41.2	19.9	16.4
Asset retirement obligations (4)	116.9	2.3	36.9	1.0	76.7
Derivative liabilities (5)	75.8	63.1	12.7	—	—
Other (6)	36.4	4.0	17.5	14.9	—
Total	$4,306.3	$357.4	$741.4	$872.9	$2,334.6

(1) Long-term debt consists of our Senior Notes and Senior Convertible Notes and assumes no principal repayment until the due dates of the instruments. The actual payment dates may vary significantly. As of December 31, 2018, we had a zero balance on our revolving credit facility.

(2) Interest payments on our Senior Notes and Senior Convertible Notes are estimated assuming no principal repayment until the due dates of the instruments. As our credit facility balance was zero at December 31, 2018, the above table includes only the fee that would be paid on the unused credit facility's aggregate lender commitment amount through the maturity date of the Credit Agreement.

(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, 2018. 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. Obligations related to inactive wells or wells that are not economic at current commodity price levels as of December 31, 2018, are shown as an obligation in 1-3 years, however, there is substantial uncertainty on the

timing of plugging or re-entering these wells. 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, 2018, 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 $36.0 million, for which we have estimated the timing of future payments based on historical annual contribution amounts.

In December 2018, we entered into an agreement that included minimum drilling and completion requirements for certain existing leases. Based on our expectation that we will meet these minimum requirements, this agreement is not reflected in the Schedule of Contractual Obligations table above. Please refer to Note 6 – Commitments and Contingencies in Part II, Item 8 of this report for additional discussion on this agreement.

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 2018 or 2017, 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 the Oil and Gas Producing Activities section of 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, 2018, 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, 2018. 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 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,		
	2018 MMBOE Change	2017 MMBOE Change	2016 MMBOE Change
Revisions resulting from performance	(59.7)	7.4	(18.1)
Removal of proved undeveloped reserves no longer in our five-year development plan	(22.6)	(13.9)	(43.0)
Revisions resulting from price changes	13.5	23.1	(35.1)
Total	(68.8)	16.6	(96.2)

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, 2018	
	MMBOE Change	Percentage Change
10 percent decrease in SEC pricing (1)	(4.6)	(1)%
Average NYMEX strip pricing as of fiscal year end (2)	(12.2)	(2)%
10 percent decrease in proved undeveloped reserves (3)	(25.9)	(5)%

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(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, 2018, 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, 2018. SEC pricing of $65.56 per Bbl for oil, $3.10 per MMBtu for gas, and $33.45 per Bbl for NGLs as of December 31, 2018, compared to the five-year average NYMEX strip pricing of $50.02 per Bbl for oil, $2.70 per MMBtu for gas, and $23.67 per Bbl for NGLs as of December 31, 2018, would result in a two 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, 2018, and does not include any additional impacts to our estimated proved reserves.

Additional reserve information can be found in the Reserves section in Part I, Items 1 and 2 of this report, and in Supplemental Oil and Gas Information 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 and 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.

Proved and unproved oil and gas properties are classified as held for sale when we commit to a plan to sell the assets and there is reasonable certainty the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less costs to sell.

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 7, 2019, we do not expect any material property impairments in the first quarter of 2019 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, 2018, 2017, and 2016.

Purchase Price Allocation. Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities acquired based on their estimated fair value as of the acquisition date. Various assumptions are made when estimating fair values assigned to proved and unproved oil and gas properties including: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) future cash flows; and (vi) a market participant-based weighted average cost of capital rate. These inputs require significant judgment by management at the time of the valuation.

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 consolidated statements of operations (“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 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, 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 would have impacted total operating revenues by approximately $10.7 million in 2018. Please refer to Note 1 – Summary of Significant Accounting Policies under the heading Recently Issued Accounting Standards and 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.

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 $6.5 million for the year ended December 31, 2018.

Accounting Matters

Please refer to Recently Issued Accounting Standards under 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 greenhouse gas 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 greenhouse gas, or 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, greenhouse gas 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 greenhouse gases 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 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 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 greenhouse gas 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.

The United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. 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 greenhouse gas emission reduction goal. In addition, there have been international conventions and efforts to establish standards for the reduction of greenhouse gases 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. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases 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 greenhouse gases could have an adverse effect on our business, financial condition, and results of operations. Finally, scientists have concluded that increasing concentrations of greenhouse gases 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 greenhouse gas 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 39 percent and 46 percent of our production on a BOE basis in 2018 and 2017, 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 greenhouse gas 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 present because we believe it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, 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 that 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,		
	2018	2017	2016
	(in thousands)		
Net income (loss) (GAAP)	$508,407	$(160,843)	$(757,744)
Interest expense	160,906	179,257	158,685
Interest income [1]	(5,191)	(3,968)	(362)
Income tax expense (benefit)	143,370	(182,970)	(444,172)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	665,313	557,036	790,745
Exploration [2] [3]	49,627	48,413	58,523
Impairment of proved properties	—	3,806	354,614
Abandonment and impairment of unproved properties	49,889	12,272	80,367
Stock-based compensation expense	23,908	22,700	26,897
Net derivative (gain) loss	(161,832)	26,414	250,633
Derivative settlement gain (loss)	(135,803)	21,234	329,478
Net (gain) loss on divestiture activity	(426,917)	131,028	(37,074)
(Gain) loss on extinguishment of debt	26,740	35	(15,722)
Other, net	1,977	8,820	(4,764)
Adjusted EBITDAX (non-GAAP) [3]	900,394	663,234	790,104
Interest expense	(160,906)	(179,257)	(158,685)
Interest income [1]	5,191	3,968	362
Income tax (expense) benefit	(143,370)	182,970	444,172
Exploration [2] [3]	(49,627)	(48,413)	(58,523)
Amortization of debt discount and deferred financing costs	15,258	16,276	9,938
Deferred income taxes	141,708	(192,066)	(448,643)
Other, net [3]	(1,690)	(935)	(5,167)
Changes in current assets and liabilities	13,671	69,613	(20,754)
Net cash provided by operating activities (GAAP) [3]	$720,629	$515,390	$552,804

(1) Interest income is included within the other non-operating income (expense), net line item on the accompanying statements of operations in Part II, Item 8 of this report.

(2) 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.

(3) Certain prior period amounts have been adjusted to conform to the current period presentation on the consolidated financial statements. Please refer to Note 1 – Summary of Significant Accounting Policies in Part II, Item 8 of this report for additional discussion.

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 under 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, 2018 and 2017, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 21, 2019 expressed an unqualified opinion thereon.

Adoption of ASU No. 2016-09

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for share-based arrangements in the December 31, 2017 consolidated financial statements due to the adoption of ASU No. 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting.

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.

/s/ Ernst & Young LLP

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

February 21, 2019

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

	December 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$77,965	$313,943
Accounts receivable	167,536	160,154
Derivative assets	175,130	64,266
Prepaid expenses and other	8,632	10,752
Total current assets	429,263	549,115
Property and equipment (successful efforts method):		
Proved oil and gas properties	7,278,362	6,139,379
Accumulated depletion, depreciation, and amortization	(3,417,953)	(3,171,575)
Unproved oil and gas properties	1,581,401	2,047,203
Wells in progress	295,529	321,347
Properties held for sale, net	5,280	111,700
Other property and equipment, net of accumulated depreciation of $57,102 and $49,985, respectively	88,546	106,738
Total property and equipment, net	5,831,165	5,554,792
Noncurrent assets:		
Derivative assets	58,499	40,362
Other noncurrent assets	33,935	32,507
Total noncurrent assets	92,434	72,869
Total assets	$6,352,862	$6,176,776
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$403,199	$386,630
Derivative liabilities	62,853	172,582
Total current liabilities	466,052	559,212
Noncurrent liabilities:		
Revolving credit facility	—	—
Senior Notes, net of unamortized deferred financing costs	2,448,439	2,769,663
Senior Convertible Notes, net of unamortized discount and deferred financing costs	147,894	139,107
Asset retirement obligations	91,859	103,026
Asset retirement obligations associated with oil and gas properties held for sale	—	11,369
Deferred income taxes	223,278	79,989
Derivative liabilities	12,496	71,402
Other noncurrent liabilities	42,522	48,400
Total noncurrent liabilities	2,966,488	3,222,956
Commitments and contingencies (note 6)		
Stockholders’ equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 112,241,966 and 111,687,016 shares, respectively	1,122	1,117
Additional paid-in capital	1,765,738	1,741,623
Retained earnings [1]	1,165,842	665,657
Accumulated other comprehensive loss [1]	(12,380)	(13,789)

Total stockholders’ equity	2,920,322	2,394,608
Total liabilities and stockholders’ equity	$6,352,862	$6,176,776

(1) The Company reclassified $3.0 million of tax effects stranded in accumulated other comprehensive loss to retained earnings as of January 1, 2018. Please refer to Note 1 – Summary of Significant Accounting Policies for further detail.

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

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

	For the Years Ended December 31,		
	2018	2017 (as adjusted)	2016 (as adjusted)
Operating revenues and other income:			
Oil, gas, and NGL production revenue	$1,636,357	$1,253,783	$1,178,426
Net gain (loss) on divestiture activity	426,917	(131,028)	37,074
Other operating revenues	3,798	6,621	1,950
Total operating revenues and other income	2,067,072	1,129,376	1,217,450
Operating expenses:			
Oil, gas, and NGL production expense	487,367	507,906	597,565
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	665,313	557,036	790,745
Exploration	55,166	54,713	64,970
Impairment of proved properties	—	3,806	354,614
Abandonment and impairment of unproved properties	49,889	12,272	80,367
General and administrative	116,504	117,283	124,828
Net derivative (gain) loss	(161,832)	26,414	250,633
Other operating expenses, net	18,328	13,667	10,772
Total operating expenses	1,230,735	1,293,097	2,274,494
Income (loss) from operations	836,337	(163,721)	(1,057,044)
Interest expense	(160,906)	(179,257)	(158,685)
Gain (loss) on extinguishment of debt	(26,740)	(35)	15,722
Other non-operating income (expense), net	3,086	(800)	(1,909)
Income (loss) before income taxes	651,777	(343,813)	(1,201,916)
Income tax (expense) benefit	(143,370)	182,970	444,172
Net income (loss)	$508,407	$(160,843)	$(757,744)
Basic weighted-average common shares outstanding	111,912	111,428	76,568
Diluted weighted-average common shares outstanding	113,502	111,428	76,568
Basic net income (loss) per common share	$4.54	$(1.44)	$(9.90)
Diluted net income (loss) per common share	$4.48	$(1.44)	$(9.90)

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,		
	2018	2017	2016
Net income (loss)	$508,407	$(160,843)	$(757,744)
Other comprehensive income (loss), net of tax:			
Pension liability adjustment [1]	4,378	767	(1,154)
Total other comprehensive income (loss), net of tax	4,378	767	(1,154)
Total comprehensive income (loss)	$512,785	$(160,076)	$(758,898)

(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.

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

	Common Stock		Additional Paid-in	Retained	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Earnings	Loss	Equity
Balances, January 1, 2016	68,075,700	$ 681	$ 305,607	$ 1,559,515	$ (13,402)	$ 1,852,401
Net loss	—	—	—	(757,744)	—	(757,744)
Other comprehensive loss	—	—	—	—	(1,154)	(1,154)
Cash dividends, $ 0.10 per share	—	—	—	(7,751)	—	(7,751)
Issuance of common stock under Employee Stock Purchase Plan	218,135	2	4,196	—	—	4,198
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	199,243	2	(2,356)	—	—	(2,354)
Stock-based compensation expense	53,473	1	26,896	—	—	26,897
Issuance of common stock from stock offerings, net of tax	42,710,949	427	1,382,666	—	—	1,383,093
Equity component of 1.50% Senior Convertible Notes due 2021 issuance, net of tax	—	—	33,575	—	—	33,575
Purchase of capped call transactions	—	—	(24,195)	—	—	(24,195)
Other	—	—	(9,833)	—	—	(9,833)
Balances, December 31, 2016	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

(1) 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.

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

	For the Years Ended December 31,		
	2018	2017	2016
Cash flows from operating activities:			
Net income (loss)	$508,407	$(160,843)	$(757,744)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Net (gain) loss on divestiture activity	(426,917)	131,028	(37,074)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	665,313	557,036	790,745
Impairment of proved properties	—	3,806	354,614
Abandonment and impairment of unproved properties	49,889	12,272	80,367
Stock-based compensation expense	23,908	22,700	26,897
Net derivative (gain) loss	(161,832)	26,414	250,633
Derivative settlement gain (loss)	(135,803)	21,234	329,478
Amortization of debt discount and deferred financing costs	15,258	16,276	9,938
(Gain) loss on extinguishment of debt	26,740	35	(15,722)
Deferred income taxes	141,708	(192,066)	(448,643)
Other, net	287	7,885	(9,931)
Changes in current assets and liabilities:			
Accounts receivable	(30,152)	13,997	(10,562)
Prepaid expenses and other	(729)	(1,953)	8,478
Accounts payable and accrued expenses	23,819	44,985	(53,210)
Accrued derivative settlements	20,733	12,584	34,540
Net cash provided by operating activities	720,629	515,390	552,804
Cash flows from investing activities:			
Net proceeds from the sale of oil and gas properties	748,509	776,719	946,062
Capital expenditures	(1,303,188)	(888,353)	(629,911)
Acquisition of proved and unproved oil and gas properties	(33,255)	(89,896)	(2,183,790)
Net cash used in investing activities	(587,934)	(201,530)	(1,867,639)
Cash flows from financing activities:			
Proceeds from credit facility	—	406,000	947,000
Repayment of credit facility	—	(406,000)	(1,149,000)
Net proceeds from senior notes	492,079	—	491,640
Cash paid to repurchase senior notes, including premium	(845,002)	(2,357)	(29,904)
Net proceeds from Senior Convertible Notes	—	—	166,617
Cash paid for capped call transactions	—	—	(24,195)
Net proceeds from sale of common stock	3,187	2,623	938,268
Dividends paid	(11,191)	(11,144)	(7,751)
Other, net	(7,746)	(1,411)	(5,486)
Net cash provided by (used in) financing activities	(368,673)	(12,289)	1,327,189
Net change in cash, cash equivalents, and restricted cash [(1)]	(235,978)	301,571	12,354
Cash, cash equivalents, and restricted cash at beginning of period [(1)]	313,943	12,372	18
Cash, cash equivalents, and restricted cash at end of period [(1)]	$77,965	$313,943	$12,372

(1) Cash, cash equivalents, and restricted cash for the year ended December 31, 2016, includes $3.0 million of restricted cash which is included in other noncurrent assets on the accompanying balance sheets.

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

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

Supplemental schedule of additional cash flow information and non-cash activities:

	For the Years Ended December 31,		
	2018	2017	2016
Operating activities:			
Cash paid for interest, net of capitalized interest	$(150,727)	$(164,097)	$(129,761)
Net cash paid (refunded) for income taxes	$2,995	$5,986	$(4,690)
Investing activities:			
Changes in capital expenditure accruals and other	$(2,774)	$7,309	$8,044
Supplemental non-cash investing activities:			
Carrying value of properties exchanged	$95,121	$293,963	$733
Supplemental non-cash financing activities:			
Issuance of common stock for an asset acquisition [(1)]	$—	$—	$437,194
Non-cash (gain) loss on extinguishment of debt, net	$6,334	$22	$(15,722)

[(1)] Refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions and Note 13 – Equity for additional discussion.

SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO 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 onshore North America.
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, 2018, 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 and Restricted Cash
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. Restricted cash includes cash that is contractually restricted for its use through an agreement with a non-related party. The Company includes restricted cash in other noncurrent assets on the accompanying balance sheets.
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 15 – 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 Company had the following major customers and sales to entities under common ownership, which 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,		
	2018	2017	2016
Major customer #1 [1]	18%	6 %	—%
Major customer #2 [1]	10%	10%	5 %
Group #1 of entities under common ownership [2]	18%	17%	15%
Group #2 of entities under common ownership [2]	12%	8 %	8 %

(1) These major customers are purchasers of a portion of the Company's production from its Permian region.

(2) In the aggregate, these groups of entities under common ownership represented 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 represented more than 10 percent of the Company's total oil, gas, and NGL production revenue.

The Company's policy is to use the commodity affiliates of the lenders under its Credit Agreement as its derivative counterparties, and each counterparty must have investment grade senior unsecured debt ratings. Each of the Company's 10 derivative counterparties meet both of these requirements as of the filing of this report.

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 with a common geological structure) 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 cash flows from investing activities 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.

Assets Held for Sale

Any properties held for sale as of the balance sheet date have been classified as assets held for sale and are separately presented on the accompanying balance sheets at the lower of carrying value or fair value less the estimated cost to sell. Properties classified as held for sale, including any corresponding asset retirement obligation liability, are valued using a market approach, based on an estimated net selling price, as evidenced by the most current bid prices received from third-parties, if available. If an estimated selling price is not available, the Company utilizes the various valuation techniques discussed above. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions.

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 proved oil and gas properties 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 operating section of the Company's 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, 2018, and 2017.

Derivative Financial Instruments

The Company periodically enters into derivative commodity instruments to reduce its exposure to pricing volatility for a portion of its expected future oil, natural gas, and NGL production. These instruments typically include commodity price swaps and costless collars, as well as, basis differential swaps. Derivative instruments are measured at fair value and are included in the accompanying consolidated balance sheets as assets and/or liabilities. The Company does not designate its derivative instruments to qualify for hedge accounting. 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 cash flows from operations in the accompanying consolidated statement of cash flows. For additional discussion on derivatives, please see 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 control of the product transfers to the customer, which differs depending on the contractual terms of each of the Company's arrangements. 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, 2018, the Company had stock-based employee compensation plans that included restricted stock units ("RSUs") and performance share units ("PSUs") issued to employees and RSUs and restricted stock issued to non-employee directors, as well as 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 general and administrative and exploration expense 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 restricted stock units, contingent Performance Share Units, 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). 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 zero balance under its credit facility as of December 31, 2018, and 2017. The Company's Senior Notes and Senior Convertible Notes are recorded at cost, net of any unamortized discount and deferred financing costs, and the respective fair values are disclosed in Note 11 – Fair Value Measurements. 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 2018 or 2017.

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 adjustment 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. Please refer to Note 4 – Income Taxes for additional discussion.

Effective December 31, 2017, the Company early adopted, on a retrospective basis, FASB ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (“ASU 2016-15”) and FASB ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (“ASU 2016-18”). ASU 2016-15 is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The Company determined that of the eight issues addressed in ASU 2016-15, only the issue related to debt extinguishment costs impacted the Company’s consolidated financial statements and disclosures. In accordance with ASU 2016-15, the Company reclassified certain debt extinguishment costs from operating activities to financing activities. ASU 2016-18 is intended to clarify guidance on the classification and presentation of restricted cash and restricted cash equivalents in the statement of cash flows. In accordance with ASU 2016-18, the Company reclassified $3.0 million of restricted cash out of investing activities and combined it with cash and cash equivalents in the accompanying statements of cash flows for the year ended December 31, 2016.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) (“ASU 2014-09”). Under the new standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The standard requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The FASB issued several additional ASUs related to ASU 2014-09 that provide clarified implementation guidance and deferred the effective date of ASU 2014-09. Effective January 1, 2018, the Company adopted ASU 2014-09 and all related ASUs using the modified retrospective transition method, which was applied to all active contracts as of the effective date. The adoption of ASU 2014-09 did not result in a change to current or prior period results nor did it result in a material change to the Company’s business processes, systems, or controls. However, upon adoption, the Company expanded its disclosures to comply with the disclosure requirements of ASU 2014-09. Please refer to Note 2 - Revenue from Contracts with Customers for additional discussion.

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”). ASU 2016-02 requires lessees to recognize right-of-use assets and lease payment liabilities on the balance sheet for leases representing the Company’s right to use the underlying assets for the lease term. Each lease that is recognized in the balance sheet will be classified as either finance or operating, with such classification affecting the pattern and classification of expense recognition in the consolidated statements of operations and presentation within the statements of cash flows.

The Company leveraged a dedicated project team and external consultants to evaluate the impacts of ASU 2016-02, which included an analysis of contracts for office leases, drilling rig agreements, well completion agreements, midstream agreements, water handling agreements, certain field equipment rentals, land easements, and other arrangements that included potential lease components. 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. The Company has completed the process of reviewing and determining contracts to which the new guidance applies, and has implemented policies, internal controls, and processes that are necessary to support the additional accounting and disclosure requirements going forward. The lease administration system that will support the on-going maintenance and accounting after adoption is operational and is currently being populated with the necessary lease data and relevant assumptions. Policy elections and practical expedients the Company has implemented as part of adopting 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 allows the Company to avoid reassessing contracts that commenced prior to adoption that were properly evaluated under legacy GAAP, (d) excluding land easements that existed or expired before adoption of ASU 2016-02, and (e) the policy election that eliminates the need for adjusting prior period comparable financial statements prepared under legacy lease accounting guidance. The Company adopted ASU 2016-02 on January 1, 2019, using the modified retrospective approach, and has necessary staff and processes in place to ensure on-going compliance. Adoption of this guidance will result in an increase in right-of-use assets and related liabilities on the Company’s consolidated balance sheets.

In January 2017, the FASB issued ASU No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business (“ASU 2017-01”). ASU 2017-01 clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The Company adopted ASU 2017-01 on the effective date of January 1, 2018, on a prospective basis.

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.

The accompanying statements of operations line items that were adjusted as a result of the adoption of ASU 2017-07 for the years ended December 31, 2017, and 2016 are summarized as follows:

	For the Year Ended December 31, 2017		For the Year Ended December 31, 2016	
	As Reported	As Adjusted	As Reported	As Adjusted
	(in thousands)			
Operating expenses:				
Exploration	$56,179	$54,713	$65,641	$64,970
General and administrative	$120,585	$117,283	$126,428	$124,828
Total operating expenses	$1,297,865	$1,293,097	$2,276,765	$2,274,494
Income (loss) from operations	$(168,489)	$(163,721)	$(1,059,315)	$(1,057,044)
Other non-operating income (expense), net	$3,968	$(800)	$362	$(1,909)

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. 2018-14, Compensation-Retirement Benefits-Defined Benefit Plans-General (Subtopic 715-20): Disclosure Framework-Changes to the Disclosure Requirements for Defined Benefit Plans (“ASU 2018-14”). ASU

2018-14 provides updated disclosure requirements related to retirement benefits and defined pension plans with the purpose of improving the effectiveness of disclosures with regard to such topics. The guidance is to be applied using a retrospective method and is effective for fiscal years ending after December 15, 2020, with early adoption permitted. The Company early adopted ASU 2018-14 on December 31, 2018, and it did not result in a material impact to the Company's consolidated financial statements or disclosures.

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 expects to adopt ASU 2018-15 on January 1, 2020, with prospective application. The Company is evaluating the impact of ASU 2018-15 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, 2018, 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 Permian, South Texas & Gulf Coast, and Rocky Mountain regions. During the first quarter of 2018, the Company entered into two definitive agreements to sell all of its producing properties in its Rocky Mountain region. One transaction closed in the first quarter of 2018, and the second transaction closed in the second quarter of 2018. As a result of these divestitures, there has been no production revenue from the Rocky Mountain region after the second quarter of 2018. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions for additional detail. 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 disaggregation of oil, gas, and NGL production revenue by product type for each of the Company's operating regions for the years ended December 31, 2018, 2017, and 2016:

	For the year ended December 31, 2018			
	Permian	South Texas & Gulf Coast	Rocky Mountain	Total
	(in thousands)			
Oil, gas, and NGL production revenue:				
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			
	Permian	South Texas & Gulf Coast	Rocky Mountain	Total
	(in thousands)			
Oil, gas, and NGL production revenue:				
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.

	For the year ended December 31, 2016			
	Permian	South Texas & Gulf Coast	Rocky Mountain	Total
	(in thousands)			
Oil, gas, and NGL production revenue:				
Oil production revenue	$117,399	$189,313	$305,126	$611,838
Gas production revenue	17,315	308,829	11,144	337,288
NGL production revenue	92	225,821	3,387	229,300
Total	$134,806	$723,963	$319,657	$1,178,426
Relative percentage	11 %	62 %	27 %	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 customer, which differs depending on the contractual terms of each of the Company's arrangements. 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 prior to control transfer are recorded within the oil, gas, and NGL production expense line item on the accompanying statements of operations, while fees and other deductions incurred subsequent to control transfer are recorded as a reduction of oil, gas, and NGL production revenue. The Company has four categories under which oil, gas, and NGL production revenue is generated. Each of the Company's operating regions generate production revenue from a combination of some or all of the four different contract types summarized below:

1) The Company sells oil production at or near the wellhead and receives an agreed-upon index price from the purchaser, net of basis, quality, and transportation differentials. Under this arrangement, control transfers at or near the wellhead.
2) The Company sells unprocessed gas to a midstream processor at the wellhead or inlet of the midstream processing facility. The midstream processor gathers and processes the raw gas stream and remits proceeds to the Company from the ultimate sale of the processed NGLs and residue gas to third parties. In such arrangements, the midstream processor obtains control of the product at the wellhead or inlet of the facility and is considered the customer. Proceeds received for unprocessed gas under these arrangements are reflected as gas production revenue and are recorded net of transportation and processing fees incurred by the midstream processor after control has transferred.
3) 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 it generates from selling the NGLs to other 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 gathering, transportation, and processing fees 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.
4) The Company has certain midstream processing arrangements where unprocessed gas is delivered to the inlet of the midstream processor's facility for processing. Upon completion of processing, the midstream processor purchases the processed NGLs and residue gas and remits the proceeds to the Company from the sale of the products to third-party customers. In these arrangements, control transfers at the tailgate of the midstream processing facility for both products. Given the structure of these arrangements and where control transfers, the Company separately recognizes gathering, transportation, and processing fees 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 predictable differentials. Accordingly, the Company does not consider estimates of variable consideration to be constrained.

The Company’s contractual 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 customer 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 contractual 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 accounts receivable 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, 2018 and December 31, 2017, were $107.2 million and $96.6 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. Revenue recognized for the year ended December 31, 2018, that related to performance obligations satisfied in prior reporting periods, was immaterial.

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

2018 Divestiture Activity

PRB Divestiture. On March 26, 2018, the Company divested approximately 112,000 net acres of its Powder River Basin assets for net divestiture proceeds of $492.2 million, and recorded a final net gain of $410.6 million for the year ended December 31, 2018. These assets were recorded as properties held for sale as of December 31, 2017.

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. A portion of these assets were recorded as properties held for sale as of December 31, 2017.

The following table presents loss before income taxes from the Divide County, North Dakota assets sold for the years ended December 31, 2018, 2017, and 2016. The Divide County Divestiture was considered a disposal of a significant asset group.

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Loss before income taxes [(1)]	$(28,975)	$(468,786)	$(50,034)

(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 previously held for sale.

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.

The following table presents income (loss) before income taxes from the outside-operated Eagle Ford shale assets sold for the years ended December 31, 2018, 2017, and 2016. This divestiture was considered a disposal of a significant asset group.

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Income (loss) before income taxes [(1)]	$—	$24,324	$(218,506)

(1) Income (loss) before income taxes reflects oil, gas, and NGL production revenue, less oil, gas, and NGL production expense, and depletion, depreciation, amortization, and asset retirement obligation liability accretion.

Additionally, income (loss) before income taxes includes $269.6 million of impairment of proved properties expense for the year ended December 31, 2016.

Rocky Mountain and Permian Divestitures. During 2017, the Company divested certain non-core properties in its Rocky Mountain and Permian regions for net divestiture proceeds of $36.2 million and recognized an insignificant final net gain.

2016 Divestiture Activity
Rocky Mountain Divestitures. During the third quarter of 2016, the Company divested certain non-core properties in the Williston Basin and Powder River Basin in two separate transactions for combined net divestiture proceeds of $110.3 million and a final net gain of $16.4 million.
During the fourth quarter of 2016, the Company divested certain Williston Basin assets located outside of Divide County, North Dakota (referred to as "Raven/Bear Den" throughout this report) for net divestiture proceeds of $755.7 million and a final net gain of $29.5 million. In conjunction with this divestiture, the Company closed its Billings, Montana regional office.
Permian Divestiture. During the third quarter of 2016, the Company divested its non-core properties in southeast New Mexico for net divestiture proceeds of $54.7 million and recorded a final net loss of $10.0 million.
The Company finalized these divestitures in 2017.
The Company determined that neither planned nor executed asset sales in 2018, 2017, and 2016 qualify for discontinued operations accounting under financial statement presentation authoritative guidance.
Properties Held for Sale
Assets are classified as held for sale when the Company commits to a plan to sell the assets and it is probable the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less estimated costs to sell. When assets no longer meet the criteria of assets held for sale, they are measured at the lower of the carrying value of the assets before being classified as held for sale, adjusted for any depletion, depreciation, and amortization expense that would have been recognized, or the fair value at the date they are reclassified to assets held for use. Any gain or loss recognized on assets held for sale or on assets held for sale that are subsequently reclassified to assets held for use is reflected in the net gain (loss) on divestiture activity line item on the accompanying statements of operations.

As of December 31, 2018, and 2017, there were $5.3 million and $111.7 million, respectively, of assets held for sale presented on the accompanying balance sheets. The balance as of December 31, 2017, consisted primarily of approximately 112,000 net acres in the Powder River Basin, and is presented net of accumulated depletion, depreciation, and amortization expense. As discussed above, the Company sold these assets in the first quarter of 2018.
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 unproved properties, located in Howard and Martin Counties, Texas, resulting in the Company exchanging approximately 2,650 net acres, with $95.1 million of carrying value attributed to the properties surrendered by the Company. These trades were recorded at carryover basis with no gain or loss recognized.
Subsequent to December 31, 2018, the Company completed several non-monetary acreage trades of primarily unproved properties, located in Howard, Martin, and Upton Counties, Texas, resulting in the Company receiving approximately 1,580 net acres in exchange for approximately 1,650 net acres.
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 considered asset acquisitions and the properties were recorded based on the fair value of the total consideration transferred on the acquisition date and 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 Company acquiring approximately 8,125 net acres in exchange for approximately 7,580 net acres with $294.0 million of carrying value attributed to the properties surrendered by the Company in such trades. These trades were recorded at carryover basis with no gain or loss recognized.

2016 Acquisition Activity

Rock Oil Acquisition. During the fourth quarter of 2016, the Company acquired all membership interests of JPM EOC Opal, LLC, which owned proved and unproved properties in the Midland Basin, from Rock Oil Holdings, LLC (referred to as the "Rock Oil Acquisition"). The Company finalized the Rock Oil Acquisition during 2017 by paying $7.7 million of cash consideration in addition to the initial adjusted purchase price of $991.0 million, resulting in total consideration of $998.7 million paid after final closing adjustments. The Company funded the acquisition with proceeds from divestitures in 2016, the Senior Convertible Notes and equity offerings in August 2016, and the 2026 Senior Notes offering in September 2016, as discussed in Note 5 – Long-Term Debt and Note 13 – Equity, respectively. The Company determined that the Rock Oil Acquisition met the criteria of a business combination under ASC Topic 805, Business Combinations. The Company allocated the final adjusted purchase price to the acquired assets and liabilities based on fair value as of the acquisition date, as summarized in the table below. This measurement resulted in no goodwill or bargain purchase gain being recognized. The acquisition costs were insignificant and were expensed as incurred.

	As of October 4, 2016 (in thousands)
Cash consideration	$ 998,691
Fair value of assets and liabilities acquired:	
Wells in progress	$ 5,672
Proved oil and gas properties	82,584
Unproved oil and gas properties	913,819
Other assets	5,338
Total fair value of oil and gas properties acquired	1,007,413
Working capital	(1,127)
Asset retirement obligations	(7,595)
Total fair value of net assets acquired	$ 998,691

QStar Acquisition. During the fourth quarter of 2016, the Company acquired additional proved and unproved properties in the Midland Basin from QStar LLC and RRP-QStar, LLC (referred to as the "QStar Acquisition"). The Company finalized the QStar Acquisition during the third quarter of 2017 by paying $7.3 million of cash consideration in addition to the initial consideration of $1.2 billion in cash consideration and the issuance of approximately 13.4 million shares of the Company's common stock, resulting in total consideration of approximately $1.6 billion paid after final closing adjustments. The Company funded the acquisition with proceeds from the 2016 divestitures and the December 2016 equity offering. Please refer to Note 13 – Equity for additional discussion.

Under authoritative accounting guidance, the transaction was considered an asset acquisition, and therefore, the properties were recorded based on the fair value of the total consideration transferred on the acquisition date and transaction costs were capitalized as a component of the cost of the assets acquired. The Company allocated the final adjusted purchase price to the acquired assets and liabilities, as summarized in the table below.

	As of December 21, 2016 (in thousands)
Cash consideration, including acquisition costs paid	$1,174,628
Fair value of equity consideration [1]	437,194
Total consideration	$1,611,822
Assets and liabilities acquired:	
Wells in progress	$21,812
Proved oil and gas properties	61,239
Unproved oil and gas properties	1,538,264
Total oil and gas properties acquired	1,621,315
Working capital	(1,852)
Asset retirement obligations	(7,641)
Total net assets acquired	$1,611,822

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(1) The Company issued approximately 13.4 million shares of common stock, par value $0.01 per share, in a private placement to the sellers in the QStar Acquisition on December 21, 2016. The equity consideration was valued on this date using Level 1 and Level 2 inputs with a discount applied due to the lack of marketability in the near term in accordance with the Lock-Up and Registration Rights Agreement that prohibited the sale of such stock until no earlier than the 90th day after issuance.

Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Current portion of income tax expense (benefit)			
Federal	$—	$5,698	$2,932
State	1,662	3,398	1,539
Deferred portion of income tax expense (benefit)	141,708	(192,066)	(448,643)
Total income tax expense (benefit)	$143,370	$(182,970)	$(444,172)
Effective tax rate	22.0 %	53.2 %	37.0 %

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

	As of December 31,	
	2018	2017
	(in thousands)	
Deferred tax liabilities		
Oil and gas properties	$218,094	$142,467
Derivative assets	35,247	—
Other	4,812	3,412
Total deferred tax liabilities	258,153	145,879
Deferred tax assets		
Derivative liabilities	—	29,463
Credit carryover	22,554	22,537
Pension	6,427	7,986
Federal and state tax net operating loss carryovers	4,217	3,867
Stock compensation	3,263	3,545
Other liabilities	1,497	1,470
Total deferred tax assets	37,958	68,868
Valuation allowance	(3,083)	(2,978)
Net deferred tax assets	34,875	65,890
Total net deferred tax liabilities	$223,278	$79,989
Current federal income tax refundable	$59	$37
Current state income tax payable	$1,331	$3,009

The enactment of the 2017 Tax Act on December 22, 2017 reduced the Company's federal tax rate for 2018 and future years from 35 percent to 21 percent. With the conclusion of the one-year measurement period and considering subsequent guidance, the Company believes it has properly analyzed the tax accounting impacts of the 2017 Tax Act, including the $1.0 million limitation on the compensation of certain covered individuals, which impacts the Company's tax rate. There are no new estimates or finalized income tax items associated with the 2017 Tax Act included in income tax (expense) benefit for the year ended December 31, 2018.

As of December 31, 2018, the Company estimated its federal net operating loss ("NOL") carryforward at $2.3 million, which reflects the planning strategies to utilize NOLs for the 2017 and 2016 tax years. In 2017, the Company re-evaluated various factors affecting deferred tax assets related to net operating losses and tax credits and determined utilization would be appropriate. The change in the current quarter portion of income tax (expense) benefit between periods reflects the effect of this determination. The Company expects to receive the 2018 federal current portion of income tax expense as a credit against tax in a future period. See the credit discussion below.

After the adoption of ASU 2016-09 in 2017, the Company no longer records a deferred tax amount for unrecognized excess income tax benefits associated with employee share-based payment awards. A cumulative effect adjustment was recorded to the beginning deferred income tax balance and retained earnings as of January 1, 2017. Please refer to Note 1 – Summary of Significant Accounting Policies above for additional information regarding the adoption of ASU 2016-09.

The Company has federal research and development ("R&D") and AMT credit carryforwards of $7.4 million and $15.6 million, respectively. The federal R&D credit carryforwards expire between 2028 and 2034. The Company's AMT credit carryforwards do not expire and are expected to be fully refunded by 2022. State NOL carryforwards were $79.7 million and state tax credits were $212,000 as of December 31, 2018. Federal and state NOLs and state credits expire between 2019 and 2038. 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. The change in the valuation allowance from 2017 to 2018 primarily relates to an allocable change to the Company's mix of state apportioned losses and anticipated utilization of state cumulative NOLs.

Federal income tax expense (benefit) differs from the amount that would be provided by applying the statutory United States federal income tax rate to income before income taxes primarily due to the effect of state income taxes, excess tax benefits and deficiencies from share-based payment awards, changes in valuation allowances, R&D credits, and accumulated impacts of other smaller permanent differences, and is reported as follows:

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Federal statutory tax expense (benefit)	$136,873	$(120,335)	$(420,671)
Increase (decrease) in tax resulting from:			
Federal tax reform changes - 2017 Tax Act	—	(63,675)	—
State tax expense (benefit) (net of federal benefit)	2,771	(3,286)	(17,549)
Change in valuation allowance	105	(2,727)	(5,059)
Employee share-based compensation	2,508	8,190	—
Other	1,113	(1,137)	(893)
Income tax expense (benefit)	$143,370	$(182,970)	$(444,172)

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.

The Company and its subsidiaries file federal income tax returns and various state income tax returns. The Company is generally no longer subject to United States federal or state income tax examinations by tax authorities for years before 2015. During the third quarter of 2018, the IRS finalized its examination of the net operating loss ("NOL") claims back to tax years 2003 through 2005 with no changes to claimed amounts. The Company received $5.9 million and $5.5 million of cash refunds in 2018 and 2017, respectively, for NOL carryback claims. During 2016, the Company's 2007 - 2011 IRS examination was finalized, with no material adjustments to previously recorded amounts.

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 2019.

The total amount recorded for unrecognized tax benefits is presented below:

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Beginning balance	$446	$446	$2,782
Additions for tax positions of prior years	—	—	9
Settlements	—	—	(2,345)
Ending balance	$446	$446	$446

Note 5 – Long-Term Debt

Credit Agreement

On September 28, 2018, the Company and its lenders entered into the Sixth Amended and Restated Credit Agreement. The Credit Agreement, which replaced the Company's Fifth Amended and Restated Credit Agreement, provides for a senior secured revolving credit facility with a maximum loan amount of $2.5 billion, an initial borrowing base of $1.5 billion, and initial aggregate lender commitments totaling $1.0 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 Company does not expect a material change to the borrowing base or the aggregate lender commitments during the next scheduled redetermination on April 1, 2019.

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 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. The Company was in compliance with all financial and non-financial covenants as of December 31, 2018, and through the filing of this report.

Interest and commitment fees are accrued based on a borrowing base utilization grid set forth in the Credit Agreement. Eurodollar loans accrue interest at the London Interbank Offered Rate, plus the applicable margin from the utilization grid, and Alternate Base Rate ("ABR") or 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	1.500%	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%

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 7, 2019, and December 31, 2018, and under the Company's Fifth Amended and Restated Credit Agreement as of December 31, 2017:

	As of February 7, 2019	As of December 31, 2018	As of December 31, 2017
	(in thousands)		
Credit facility balance (1)	$—	$—	$—
Letters of credit (2)	—	200	200
Available borrowing capacity	1,000,000	999,800	924,800

Total aggregate lender commitment amount	$ 1,000,000	$ 1,000,000	$ 925,000

(1) Unamortized deferred financing costs attributable to the credit facility are presented as a component of other noncurrent assets on the accompanying balance sheets and totaled $6.4 million and $3.1 million as of December 31, 2018, and 2017, 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

During the third quarter of 2018, the Company redeemed its 2021 Senior Notes, repurchased or redeemed all of its 2023 Senior Notes, repurchased a portion of its 2022 Senior Notes, and issued its 2027 Senior Notes. As of December 31, 2018, the Company's Senior Notes consisted of 6.125% Senior Notes due 2022, 5.0% Senior Notes due 2024 ("2024 Senior Notes"), 5.625% Senior Notes due 2025 ("2025 Senior Notes"), 6.75% Senior Notes due 2026 ("2026 Senior Notes"), and 6.625% Senior Notes due 2027 (collectively referred to as "Senior Notes"). Please refer to the discussion below for additional information. The Senior Notes, net of unamortized deferred financing costs line on the accompanying balance sheets as of December 31, 2018, and 2017, consisted of the following:

	As of December 31,					
	2018			2017		
	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)					
6.50% Senior Notes due 2021	$—	$ —	$ —	$344,611	$ 2,656	$ 341,955
6.125% Senior Notes due 2022	476,796	3,921	472,875	561,796	5,800	555,996
6.50% Senior Notes due 2023	—	—	—	394,985	3,707	391,278
5.0% Senior Notes due 2024	500,000	4,688	495,312	500,000	5,610	494,390
5.625% Senior Notes due 2025	500,000	5,808	494,192	500,000	6,714	493,286
6.75% Senior Notes due 2026	500,000	6,407	493,593	500,000	7,242	492,758
6.625% Senior Notes due 2027	500,000	7,533	492,467	—	—	—
Total	$2,476,796	$ 28,357	$ 2,448,439	$2,801,392	$ 31,729	$ 2,769,663

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, 2018, 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.

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 retire $395.0 million of its 2023 Senior Notes and $85.0 million of its 2022 Senior Notes through the Tender Offer and subsequent redemption of the remaining 2023 Senior Notes not repurchased as part of the Tender Offer ("2023 Senior Notes Redemption"). Total consideration paid, including accrued interest, for the retirement of the 2023 Senior Notes and the 2022 Senior Notes was $497.8 million. As a result of the Tender Offer and the 2023 Senior Notes Redemption, the Company recorded a loss on extinguishment of debt of $16.9 million for the year ended December 31, 2018. This amount included $12.9 million of premiums paid for the Tender Offer and 2023 Senior Notes Redemption and $4.0 million of accelerated unamortized deferred financing costs.

During the first quarter of 2016, the Company repurchased in open market transactions a total of $46.3 million in aggregate principal amount of certain of its 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, and 6.50% Senior Notes due 2023 for a settlement amount of $29.9 million, excluding interest, which resulted in a net gain on extinguishment of debt of approximately $15.7 million. This amount includes a gain of $16.4 million associated with the discount realized upon repurchase, which was partially offset by approximately $700,000 related to the acceleration of unamortized deferred financing costs.

2021 Senior Notes. On June 15, 2018, the Company called for redemption all of the $344.6 million principal outstanding on its 2021 Senior Notes at a redemption price of 102.167% of the principal amount, plus accrued and unpaid interest on the principal amount of the 2021 Senior Notes redeemed (“2021 Senior Notes Redemption”). On July 16, 2018, the Company completed the 2021 Senior Notes Redemption, which resulted in the payment of total cash consideration, including accrued interest, of $355.9 million. The Company recorded a loss on extinguishment of debt of $9.8 million for the year ended December 31, 2018. This amount included $7.5 million associated with the premium paid for the 2021 Senior Notes Redemption and $2.3 million of accelerated unamortized deferred financing costs.

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 Notes. During the first quarter of 2016, the Company repurchased $38.2 million in aggregate principal amount of its 2022 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.

2023 Senior Notes. During the first quarter of 2016, the Company repurchased $5.0 million in aggregate principal amount of its 2023 Notes for a settlement amount of $3.3 million. During the third quarter of 2018, through the Tender Offer and 2023 Senior Notes Redemption discussed above, the Company redeemed the remaining outstanding $395.0 million in aggregate principal amount of its 2023 Senior Notes for total consideration, including accrued interest, of $408.3 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 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 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 Notes. The net proceeds were used to partially fund the Rock Oil Acquisition that closed during the fourth quarter of 2016.

2027 Senior Notes. On August 20, 2018, the Company issued $500.0 million in aggregate principal amount of 6.625% Senior Notes due 2027. The 2027 Senior Notes were issued at par and 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. The net proceeds were used to fund the Tender Offer and 2023 Senior Notes Redemption discussed above.

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, 2018, 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, 2018, 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 $10.5 million, $9.9 million, and $3.7 million for the years ended December 31, 2018, 2017, and 2016, respectively.

The net carrying amount of the liability component of the Senior Convertible Notes, as reflected on the accompanying balance sheets, consisted of the following as of December 31, 2018 and 2017:

	As of December 31,	
	2018	2017
	(in thousands)	
Principal amount of Senior Convertible Notes	$172,500	$172,500
Unamortized debt discount	(22,313)	(30,183)
Unamortized deferred financing costs	(2,293)	(3,210)
Net carrying amount	$147,894	$139,107

The net carrying amount of the equity component of the Senior Convertible Notes recorded in additional paid-in capital on the accompanying balance sheets consisted of the following as of December 31, 2018 and 2017:

	As of December 31,	
	2018	2017
	(in thousands)	
Equity component due to allocation of proceeds to equity	$40,217	$40,217
Related issuance costs	(1,375)	(1,375)
Deferred tax liability	(5,267)	(5,267)
Net carrying amount	$33,575	$33,575

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, 2018, 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 evaluated the capped call transactions under authoritative accounting guidance and determined that they should be accounted for as separate transactions and classified as equity instruments with no recurring fair value measurement recorded.

Capitalized Interest

Capitalized interest costs for the Company for the years ended December 31, 2018, 2017, and 2016, were $20.6 million, $12.6 million, and $17.0 million, respectively.

Note 6 – Commitments and Contingencies

Commitments

The Company has entered into various agreements, which include drilling rig and completion service contracts of $86.9 million, gathering, processing, transportation throughput, and delivery commitments of $287.8 million, office leases, including maintenance, of $35.5 million, fixed price contracts to purchase electricity of $29.0 million, and other miscellaneous contracts and leases of $18.3 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)
2019	$ 132,502
2020	103,169
2021	88,785
2022	70,741
2023	37,334
Thereafter	24,931
Total	$ 457,462

Drilling Rig and Completion Service Contracts

The Company has several drilling rig and completion service contracts in place to facilitate drilling and completion plans. Early termination of these contracts as of December 31, 2018, would have resulted in termination penalties of $45.9 million, which would be in lieu of paying the remaining commitments of $86.9 million included in the table above. For the year ended December 31, 2016, the Company incurred $8.7 million of expenses related to the early termination of drilling rig contracts or fees incurred for rigs placed on standby, which are recorded in the other operating expenses line item in the accompanying statements of operations. No material expenses related to early termination or standby fees were recorded by the Company for the years ended December 31, 2018, or 2017.

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, 2018, the Company has commitments to deliver a minimum of 29 MMBbl of oil, 595 Bcf of gas, and 21 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, 2018, if the Company fails to deliver any product, as applicable, the aggregate undiscounted deficiency payments total approximately $287.8 million. This amount does not include deficiency payment estimates associated with approximately 18.6 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. 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. As of the filing of this report, the Company does not expect to incur any material shortfalls with regard to these commitments.

Drilling and Completion Commitments

In December 2018, the Company entered into an agreement that included minimum drilling and completion requirements for certain existing leases. If these minimum requirements are not satisfied by March 31, 2020, the Company would be required to pay penalties based on the difference between actual development progress and the minimum development requirements. The penalties could range from zero to a maximum of $60.0 million, with the maximum exposure assuming no development activity occurred prior to March 31, 2020. As of the filing of this report, the Company is committed to and expects to meet the minimum development requirements set forth in the agreement.

Office Leases

The Company leases office space under various operating leases with terms extending as far as 2026. Rent expense, net of sublease income, for the years ended December 31, 2018, 2017, and 2016, was $4.5 million, $4.8 million, and $5.2 million, respectively. During the third quarter of 2015, the Company closed its office in Tulsa, Oklahoma and has subleased the space through the expiration of the lease. In the fourth quarter of 2018, the Company paid $1.3 million to the lessor to terminate the lease effective September 2019. The Company closed its office in Billings, Montana in November 2016 and paid $3.2 million to the lessor to terminate the lease. These lease termination fees are not reflected in the rent expense amounts above.

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 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, 2018, approximately 5.9 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.

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.

PSUs issued in 2017 and 2016, which the Company has determined to be equity awards, are subject to a combination of market and service vesting criteria. These awards are based on annualized Total Shareholder Return (“TSR”) for the performance period and the relative performance of the Company’s TSR compared with the annualized TSR of the Company’s peer group for the performance period. The fair value of these PSUs is measured at the grant date using the GBM Model. Compensation expense for these market-based PSUs is recognized on a straight-line basis within general and administrative expense and exploration expense over the vesting periods of the respective awards.

Beginning in 2018, PSUs awarded to employees include both a market criteria component and a performance criteria component. For the performance criteria component, the grant-date fair value is equal to the Company's stock price on the grant date, and compensation expense for the performance-based PSUs will be recorded over the vesting period of the award. The value being recorded will be evaluated on a quarterly basis and may be adjusted as the number of units expected to vest increases or decreases. For awards granted in 2018, the Company uses relative debt adjusted per share cash flow growth (“DACFG”) compared with the DACFG, as calculated by the Company, of its peer group as the performance criteria that is evaluated over the three-year performance period for these PSUs.

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 $10.3 million, $9.7 million, and $11.0 million for the years ended December 31, 2018, 2017, and 2016, respectively. As of December 31, 2018, there was $19.0 million of total unrecognized expense related to PSUs, which is being amortized through 2021.

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

	For the Years Ended December 31,					
	2018		2017		2016	
	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	1,533,491	$ 22.97	828,923	$ 43.25	626,328	$ 61.81
Granted	572,924	$ 24.45	977,731	$ 15.86	447,971	$ 26.56
Vested	(233,102)	$ 44.25	(94,338)	$ 85.85	(130,353)	$ 64.17
Forfeited	(162,054)	$ 21.79	(178,825)	$ 44.99	(115,023)	$ 55.59
Non-vested at end of year	1,711,259	$ 20.68	1,533,491	$ 22.97	828,923	$ 43.25

(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 2018, 2017, and 2016 was $14.0 million, $15.5 million, and $11.9 million, respectively. The PSUs fully vest on the third anniversary of the date of the grant; however, 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.

During the year ended December 31, 2018, the Company granted 572,924 PSUs to eligible employees (“2018 PSU Grant”). As outlined in the award agreement for the 2018 PSU Grant, performance measurements affecting vesting are based on a combination of relative performance of the Company’s annualized TSR compared with the annualized TSR of the Company’s peer group over the three-year performance period, and relative performance of the Company’s DACFG compared with its peer group DACFG over the three-year performance period. In addition to these performance measures, the award agreement for the 2018 PSU Grant also stipulates 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 DACFG performance relative to its peer group.

During the years ended December 31, 2018 and 2017, PSUs that were granted in 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. A summary of the shares of common stock issued to settle PSUs for the year ended December 31, 2016, is presented in the table below:

	For the Year Ended December 31, 2016
Shares of common stock issued to settle PSUs [(1)]	44,870
Less: shares of common stock withheld for income and payroll taxes	(14,809)
Net shares of common stock issued	30,061
Multiplier earned	0.2

(1) During the year ended December 31, 2016, the Company issued shares of common stock to settle PSUs that related to awards granted in 2013. 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 PSUs that vested during the years ended December 31, 2018, 2017, and 2016 was $10.3 million, $8.1 million, and $8.4 million, respectively.

Employee Restricted Stock Units

The Company grants RSUs to eligible persons as part of its long-term 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. 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, 2018, 2017, and 2016, was $10.8 million, $10.3 million, and $11.9 million, respectively. As of December 31, 2018, there was $20.0 million of total unrecognized compensation expense related to non-vested RSU awards, which is being amortized through 2021. 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.

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,					
	2018		2017		2016	
	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	1,244,262	$ 20.25	604,116	$ 37.39	543,737	$ 55.01
Granted	583,552	$ 25.77	1,020,780	$ 16.64	417,065	$ 28.08
Vested	(407,529)	$ 24.30	(246,025)	$ 43.99	(241,363)	$ 58.06
Forfeited	(177,122)	$ 17.26	(134,609)	$ 26.38	(115,323)	$ 43.52
Non-vested at end of year	1,243,163	$ 21.50	1,244,262	$ 20.25	604,116	$ 37.39

The fair value of RSUs granted to eligible employees in 2018, 2017, and 2016 was $15.0 million, $17.0 million, and $11.7 million, respectively. The RSUs granted generally vest one-third of the total grant on each anniversary of the grant dates, unless the employee is retirement eligible, in which case the RSUs generally 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.

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,		
	2018	2017	2016
Shares of common stock issued to settle RSUs [(1)]	407,529	246,025	241,363
Less: shares of common stock withheld for income and payroll taxes	(115,784)	(74,747)	(72,181)
Net shares of common stock issued	291,745	171,278	169,182

(1) During the years ended December 31, 2018, 2017, and 2016, 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, 2018, 2017, and 2016 was $9.9 million, $10.8 million, and $14.0 million, respectively.

Director Shares

In 2018, 2017, and 2016, the Company issued 63,741, 71,573, and 53,473 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, 2018, 2017, and 2016, the Company recorded $1.7 million, $1.6 million, and $2.0 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 1.6

million shares of its common stock available for issuance under the ESPP as of December 31, 2018. There were 199,464, 186,665, and 218,135 shares issued under the ESPP in 2018, 2017, and 2016, respectively.

Total proceeds to the Company for the issuance of these shares were $3.2 million, $2.6 million, and $4.2 million for the years ended December 31, 2018, 2017, and 2016, respectively.

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,		
	2018	2017	2016
Risk free interest rate	1.8 %	0.9 %	0.4 %
Dividend yield	0.4 %	0.5 %	0.4 %
Volatility factor of the expected market price of the Company's common stock	55.9%	62.5%	95.0%
Expected life (in years)	0.5	0.5	0.5

The Company expensed $1.1 million, $1.0 million, and $2.0 million for the years ended December 31, 2018, 2017, and 2016, respectively, 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 $4.9 million, $4.5 million, and $5.4 million for the years ended December 31, 2018, 2017, and 2016, respectively.

Net Profits Plan

Under the Company's Net Profits Plan, all oil and gas wells that were completed or acquired during each year were designated within a specific pool with key employees designated as participants that became entitled to payments under the Net Profits Plan after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, 10 percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the 10 percent level. In December 2007, the Board of Directors discontinued the creation of new pools under the Net Profits Plan. As a result, the 2007 pool was the last Net Profits Plan pool established by the Company.

The following table presents cash payments made or accrued under the Net Profits Plan related to periodic operations, of which the majority is recorded as general and administrative expense, and cash payments made or accrued as a result of divestitures of properties subject to the Net Profits Plan, which are recorded as a reduction to the net gain (loss) on divestiture activity line item in the accompanying statements of operations.

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Cash payments made or accrued related to operations	$63	$(54)	$6,608
Cash payments made or accrued related to divestitures	—	2,753	24,349
Total net settlements	$63	$2,699	$30,957

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 it 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 to other comprehensive income (loss), net of tax, in the accompanying statements of comprehensive income. 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,	
	2018	2017
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$71,937	$69,659
Service cost	6,730	6,638
Interest cost	2,622	2,689
Actuarial (gain) loss	(7,155)	3,708
Benefits paid	(8,048)	(10,757)
Projected benefit obligation at end of year	66,086	71,937
Change in plan assets:		
Fair value of plan assets at beginning of year	30,978	31,731
Actual return on plan assets	(964)	2,956
Employer contribution	8,134	7,048
Benefits paid	(8,048)	(10,757)
Fair value of plan assets at end of year	30,100	30,978
Funded status at end of year	$(35,986)	$(40,959)

The Company's underfunded status for the Pension Plans as of December 31, 2018, and 2017, was $36.0 million and $41.0 million, respectively, and is recognized in the accompanying balance sheets as a portion of other noncurrent liabilities. 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,	
	2018	2017
	(in thousands)	
Projected benefit obligation	$66,086	$71,937
Accumulated benefit obligation	$52,368	$56,045
Less: fair value of plan assets	(30,100)	(30,978)
Underfunded accumulated benefit obligation	$22,268	$25,067

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 accumulated other comprehensive loss as of December 31, 2018, and 2017, were as follows:

	As of December 31,	
	2018	2017
	(in thousands)	
Unrecognized actuarial losses	$15,741	$21,397
Unrecognized prior service costs	48	66
Accumulated other comprehensive loss	$15,789	$21,463

The pension liability adjustments recognized in other comprehensive income (loss) during 2018, 2017, and 2016, were as follows:

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Net actuarial gain (loss)	$4,329	$(2,995)	$(3,322)
Amortization of prior service cost	18	17	16
Amortization of net actuarial loss	1,327	1,297	1,582
Settlements	—	3,009	—
Total pension liability adjustment, pre-tax	5,674	1,328	(1,724)
Tax (expense) benefit	(4,265)	(561)	570
Cumulative effect of accounting change [(1)]	2,969	—	—
Total pension liability adjustment, net	$4,378	$767	$(1,154)

(1) 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,		
	2018	2017	2016
	(in thousands)		
Components of net periodic benefit cost:			
Service cost	$6,730	$6,638	$8,200
Interest cost	2,622	2,689	2,908
Expected return on plan assets that reduces periodic pension benefit cost	(1,862)	(2,244)	(2,235)
Amortization of prior service cost	18	17	16
Amortization of net actuarial loss	1,327	1,297	1,582
Settlements	—	3,009	—
Net periodic benefit cost	$8,835	$11,406	$10,471

Pension Plan Assumptions

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

	As of December 31,	
	2018	2017
Projected benefit obligation:		
Discount rate	4.4%	3.8%
Rate of compensation increase	6.2%	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,		
	2018	2017	2016
Net periodic benefit cost:			
Discount rate	3.8%	4.2%	4.7%
Expected return on plan assets [1]	5.5%	6.5%	7.5%
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	2019	2018	2017
Equity securities	35.0 %	31.8 %	38.4 %
Fixed income securities	43.0 %	41.3 %	39.8 %
Other securities	22.0 %	26.9 %	21.8 %
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 5.5 percent, 6.5 percent, and 7.5 percent was used to calculate the Company's net periodic pension cost under the Qualified Pension Plan for the years ended December 31, 2018, 2017, and 2016 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. We evaluate the expected rate of return on plan assets assumption on an annual basis.

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Pension Plan Assets

The fair values of the Company's Qualified Pension Plan assets as of December 31, 2018, and 2017, 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, 2018						
Cash	—	%	$—	$—	$—	$—
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:						
High-yield bonds [(4)]	—	%	—	—	—	—
Core fixed income [(5)]	34.4	%	10,342	10,342	—	—
Floating rate corporate loans [(6)]	6.9	%	2,078	2,078	—	—
Total fixed income securities	41.3	%	12,420	12,420	—	—
Other securities:						
Commodities [(7)]	—	%	—	—	—	—
Real estate [(8)]	6.0	%	1,820	—	—	1,820
Collective investment trusts [(9)]	3.1	%	934	—	934	—
Hedge fund [(10)]	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
As of December 31, 2017						
Cash	—	%	$—	$—	$—	$—
Equity securities:						
Domestic [(2)]	22.2	%	6,865	4,805	2,060	—
International [(3)]	16.2	%	5,032	3,806	1,226	—
Total equity securities	38.4	%	11,897	8,611	3,286	—
Fixed income securities:						
High-yield bonds [(4)]	2.8	%	876	876	—	—
Core fixed income [(5)]	28.6	%	8,842	8,842	—	—
Floating rate corporate loans [(6)]	8.4	%	2,607	2,607	—	—
Total fixed income securities	39.8	%	12,325	12,325	—	—
Other securities:						
Commodities [(7)]	1.9	%	588	588	—	—
Real estate [(8)]	5.6	%	1,735	—	—	1,735
Collective investment trusts [(9)]	3.1	%	959	—	959	—
Hedge fund [(10)]	11.2	%	3,474	—	—	3,474
Total other securities	21.8	%	6,756	588	959	5,209
Total investments	100.0	%	$30,978	$21,524	$4,245	$5,209

(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) High-yield bonds consist of non-investment grade fixed income securities. The investment objective is to obtain high current income. Due to the increased level of default risk, security selection focuses on credit-risk analysis.

(5) 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.

(6) 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.

(7) Investments with exposure to commodity price movements, primarily through the use of futures, swaps, and other commodity-linked securities.

(8) 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.

(9) 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.

(10) 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, 2017	$5,214
Purchases	300
Realized gain on assets	130
Unrealized gain on assets	120
Disposition	(555)
Balance at December 31, 2017	$5,209
Purchases	—
Realized gain on assets	191
Unrealized gain on assets	152
Disposition	(45)
Balance at December 31, 2018	$5,507

Contributions

The Company contributed $8.1 million, $7.0 million, and $11.0 million to the Pension Plans for the years ended December 31, 2018, 2017, and 2016, respectively. The Company expects to make a $4.0 million contribution to the Pension Plans in 2019.

Benefit Payments

The Pension Plans made actual benefit payments of $8.0 million, $10.8 million, and $6.7 million in the years ended December 31, 2018, 2017, and 2016, respectively. Expected benefit payments over the next 10 years are as follows:

Years Ending December 31,	(in thousands)
2019	$ 5,429
2020	$ 5,066
2021	$ 4,913
2022	$ 5,715
2023	$ 7,693
2024 through 2028	$ 30,400

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 adjusted net income or loss 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, 2018, and 2017, and for the portion of the year ended December 31, 2016, during which the Senior Convertible Notes were outstanding; 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, 2017, and 2016, 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 dilutive and anti-dilutive securities for the years presented:

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Dilutive	1,590	—	—
Anti-dilutive	—	264	280

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

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands, except per share data)		
Net income (loss)	$508,407	$(160,843)	$(757,744)
Basic weighted-average common shares outstanding	111,912	111,428	76,568
Dilutive effect of non-vested RSUs and contingent PSUs	1,590	—	—
Dilutive effect of Senior Convertible Notes	—	—	—
Diluted weighted-average common shares outstanding	113,502	111,428	76,568

Basic net income (loss) per common share	$4.54	$(1.44)	$(9.90)
Diluted net income (loss) per common share	$4.48	$(1.44)	$(9.90)

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, 2018, 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 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, 2018, 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 2019	826	$ 60.16
Second quarter 2019	575	$ 55.52
Third quarter 2019	1,217	$ 61.41
Fourth quarter 2019	1,115	$ 59.97
2020	2,491	$ 65.68
Total	6,224	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MBbl)	(per Bbl)	(per Bbl)
First quarter 2019	2,503	$ 51.66	$ 64.32
Second quarter 2019	2,802	$ 52.18	$ 64.61
Third quarter 2019	2,364	$ 49.07	$ 62.67
Fourth quarter 2019	2,386	$ 49.08	$ 62.65
2020	1,165	$ 55.00	$ 66.47
Total	11,220		

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 2019	2,433	$ (4.44)	—	$ —
Second quarter 2019	2,571	$ (4.49)	—	$ —
Third quarter 2019	3,291	$ (2.86)	—	$ —
Fourth quarter 2019	3,338	$ (2.87)	—	$ —
2020	11,601	$ (1.03)	2,750	$ (8.03)
2021	—	$ —	3,650	$ (7.86)
2022	—	$ —	3,650	$ (7.78)
Total	23,234		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 2019	19,805	$ 2.99	—	$ —
Second quarter 2019	10,439	$ 2.82	2,803	$ 0.69
Third quarter 2019	12,531	$ 2.82	2,984	$ 1.28
Fourth quarter 2019	14,433	$ 2.88	2,962	$ 1.75
2020	9,123	$ 2.98	2,060	$ 2.20
Total [1]	66,331		10,809	

(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, 2018, total volumes for gas swaps are comprised of 86 percent IF HSC, four percent IF Waha, and 10 percent GD Waha.

Gas Collars

Contract Period	IF HSC Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(BBtu)	(per MMBtu)	(per MMBtu)
First quarter 2019	—	$ —	$ —
Second quarter 2019	4,358	$ 2.50	$ 2.83
Third quarter 2019	5,066	$ 2.50	$ 2.83
Fourth quarter 2019	4,818	$ 2.50	$ 2.83
Total	14,242		

NGL Swaps

	OPIS Ethane Purity Mont Belvieu		OPIS Propane Mont Belvieu Non-TET		OPIS Normal Butane Mont Belvieu Non-TET		OPIS Isobutane Mont Belvieu Non-TET		OPIS Natural Gasoline Mont Belvieu Non-TET	
Contract Period	Volumes (MBbl)	Weighted-Average Contract Price (per Bbl)	Volumes (MBbl)	Weighted-Average Contract Price (per Bbl)	Volumes (MBbl)	Weighted-Average Contract Price (per Bbl)	Volumes (MBbl)	Weighted-Average Contract Price (per Bbl)	Volumes (MBbl)	Weighted-Average Contract Price (per Bbl)
First quarter 2019	853	$ 12.25	540	$ 28.72	38	$ 35.64	29	$ 35.70	48	$ 50.93
Second quarter 2019	877	$ 12.29	561	$ 31.32	38	$ 35.64	29	$ 35.70	49	$ 50.93
Third quarter 2019	907	$ 12.34	637	$ 31.29	39	$ 35.64	30	$ 35.70	50	$ 50.93
Fourth quarter 2019	896	$ 12.36	651	$ 31.64	39	$ 35.64	29	$ 35.70	50	$ 50.93
2020	539	$ 11.13	—	$ —	—	$ —	—	$ —	—	$ —
Total	4,072		2,389		154		117		197	

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. The Company does not designate its derivative commodity contracts as hedging instruments. The fair value of the derivative commodity contracts was a net asset of $158.3 million at December 31, 2018, and net liability of $139.4 million at December 31, 2017.

The following tables detail the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of December 31, 2018			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$175,130	Current liabilities	$62,853
Commodity contracts	Noncurrent assets	58,499	Noncurrent liabilities	12,496
Total commodity contracts		$233,629		$75,349

	As of December 31, 2017			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$64,266	Current liabilities	$172,582
Commodity contracts	Noncurrent assets	40,362	Noncurrent liabilities	71,402
Total commodity contracts		$104,628		$243,984

Offsetting of Derivative Assets and Liabilities

As of December 31, 2018, and 2017, 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 derivative contracts:

	Derivative Assets As of December 31,		Derivative Liabilities As of December 31,	
Offsetting of Derivative Assets and Liabilities	2018	2017	2018	2017
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$233,629	$104,628	$(75,349)	$(243,984)
Amounts not offset in the accompanying balance sheets	(56,041)	(100,035)	56,041	100,035
Net amounts	$177,588	$4,593	$(19,308)	$(143,949)

The Company recognizes 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 Company had no derivatives designated as hedging instruments for the years ended December 31, 2018, 2017, and 2016. 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 components of the net derivative (gain) loss line item presented in the accompanying statements of operations:

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Derivative settlement (gain) loss:			
Oil contracts	$68,860	$31,176	$(243,102)
Gas contracts	13,029	(87,857)	(94,936)
NGL contracts	53,914	35,447	8,560
Total derivative settlement (gain) loss	$135,803	$(21,234)	$(329,478)
Net derivative (gain) loss:			
Oil contracts	$(192,002)	$71,502	$85,370
Gas contracts	35,411	(76,315)	81,060
NGL contracts	(5,241)	31,227	84,203
Total net derivative (gain) loss	$(161,832)	$26,414	$250,633

Credit Related Contingent Features

As of December 31, 2018, 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 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, 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.

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, 2017:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$ —	$ 104,628	$ —
Liabilities:			
Derivatives (1)	$ —	$ 243,984	$ —

(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.

Proved and Unproved 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. There were no material proved oil and gas properties recorded at fair value on the accompanying balance sheets as of December 31, 2018, or December 31, 2017. The Company recorded impairment of proved properties expense of $354.6 million for the year ended December 31, 2016, related primarily to the decline in expected reserve cash flows from the Company's outside-operated Eagle Ford shale assets driven by commodity price declines during the first quarter of 2016, and downward performance reserve revisions in the fourth quarter of 2016 for the Company's Powder River Basin assets.

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.

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

	For the Years Ended December 31,		
	2018	2017	2016
	(in millions)		
Abandonment and impairment of unproved properties	$49.9	$12.3	$80.4

Abandonment and impairment of unproved properties expense recorded during the years ended December 31, 2018, and 2017, related primarily 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. During the year ended December 31, 2016, abandonment and impairment expense related primarily to a decrease in the fair value of the Company's unproved Powder River Basin properties due to downward performance reserve revisions and lower market prices based on third-party acreage transactions.

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, 2018, or 2017, 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,			
	2018		2017	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(in thousands)			
6.50% Senior Notes due 2021	$—	$—	$344,611	$351,682
6.125% Senior Notes due 2022	$476,796	$452,336	$561,796	$571,627
6.50% Senior Notes due 2023	$—	$—	$394,985	$403,434
5.0% Senior Notes due 2024	$500,000	$439,265	$500,000	$483,440
5.625% Senior Notes due 2025	$500,000	$436,460	$500,000	$494,355
6.75% Senior Notes due 2026	$500,000	$448,305	$500,000	$516,350
6.625% Senior Notes due 2027	$500,000	$442,500	$—	$—
1.50% Senior Convertible Notes due 2021	$172,500	$158,614	$172,500	$168,291

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 – Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2018, 2017, and 2016. 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,		
	2018	2017	2016
	(in thousands)		
Beginning balance	$49,446	$19,846	$11,952
Additions to capitalized exploratory well costs pending the determination of proved reserves	11,197	49,446	19,846
Divestitures	(109)	—	—
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(49,337)	(19,846)	(11,952)
Capitalized exploratory well costs charged to expense	—	—	—
Ending balance	$11,197	$49,446	$19,846

As of December 31, 2018, there were no exploratory well costs that were capitalized for more than one year.

Note 13 – Equity

On August 12, 2016, the Company completed an underwritten public offering of approximately 18.4 million shares of its common stock at an offering price of $30.00 per share. Net proceeds from the offering totaled $530.9 million, after deducting underwriting discounts and commissions and offering expenses, which the Company used to partially fund the Rock Oil Acquisition that closed during the fourth quarter of 2016.

On December 7, 2016, the Company completed an underwritten public offering of approximately 10.9 million shares of its common stock at an offering price of $38.25 per share. Net proceeds from the offering totaled $403.2 million, after deducting underwriting discounts and commissions and offering expenses, which the Company used to partially fund the QStar Acquisition that also closed during the fourth quarter of 2016.

The Company's 2016 public equity offerings were made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC.

On December 21, 2016, and as part of the QStar Acquisition, the Company issued approximately 13.4 million shares of its common stock valued at approximately $437.2 million in a private placement to the sellers as partial consideration for the acquired properties. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions for additional discussion.

The Company did not conduct any equity offerings during 2018 or 2017.

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,	
	2018	2017
	(in thousands)	
Beginning asset retirement obligations	$114,470	$123,307
Liabilities incurred [1]	4,054	7,588
Liabilities settled [2]	(33,024)	(30,432)
Accretion expense	4,438	5,988
Revision to estimated cash flows	4,256	8,019
Ending asset retirement obligations [3][4]	$94,194	$114,470

(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) Balance as of December 31, 2017, included $11.4 million of asset retirement obligations associated with oil and gas properties held for sale.

(4) Balances as of December 31, 2018, and 2017, included $2.3 million and $75,000, 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 – Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following accruals:

	As of December 31,	
	2018	2017
	(in thousands)	
Oil, gas, and NGL production revenue	$107,230	$96,610
Amounts due from joint interest owners	31,497	56,929
State severance tax refunds	4,415	2,276
Derivative settlements	9,475	99
Other	14,919	4,240
Total accounts receivable	$167,536	$160,154

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

	As of December 31,	
	2018	2017
	(in thousands)	
Drilling and lease operating cost accruals	$139,711	$126,500
Trade accounts payable	56,047	77,573
Revenue and severance tax payable	94,806	60,328
Property taxes	18,694	13,222
Compensation	31,486	39,471
Derivative settlements	1,287	12,644
Interest	40,840	45,057
Other	20,328	11,835
Total accounts payable and accrued expenses	$403,199	$386,630

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,		
	2018	2017	2016
	(in thousands)		
Development costs [(1)]	$1,147,574	$675,523	$595,331
Exploration costs	184,930	271,502	118,224
Acquisitions [(2)]			
Proved properties	1,312	1,602	201,672
Unproved properties [(3)]	55,688	91,420	2,458,667
Total, including asset retirement obligations [(4)(5)]	$1,389,504	$1,040,047	$3,373,894

(1) Includes facility costs of $72.6 million, $43.8 million, and $25.9 million for the years ended December 31, 2018, 2017, and 2016, respectively.

(2) Balances at December 31, 2016, include $437.2 million of value attributed to the equity consideration given to the sellers of the assets acquired in the QStar Acquisition. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions for additional discussion.

(3) Includes amounts related to leasing activity and acquiring surface rights outside of acquisitions of proved and unproved properties totaling $23.4 million, $12.8 million, and $7.5 million for the years ended December 31, 2018, 2017, and 2016, respectively.

(4) Includes amounts relating to estimated asset retirement obligations of $7.1 million, $13.6 million, and $32.1 million for the years ended December 31, 2018, 2017, and 2016, respectively.

(5) Includes capitalized interest of $20.6 million, $12.6 million, and $17.0 million for the years ended December 31, 2018, 2017, and 2016, 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, 2018. 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,								
	2018 (1)			2017 (2)			2016 (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	158.2	1,280.1	96.5	104.9	1,111.1	105.7	145.3	1,264.0	115.4
Revisions of previous estimate	(24.0)	(219.5)	(8.0)	1.0	63.8	4.9	(36.0)	(249.8)	(18.6)
Discoveries and extensions	9.3	20.3	0.5	11.5	21.9	—	7.8	42.5	4.1
Infill reserves in an existing proved field	80.4	391.5	29.0	79.0	347.4	22.9	32.3	228.1	18.9
Sales of reserves (4)	(29.6)	(48.1)	(2.7)	(25.3)	(143.8)	(26.7)	(40.0)	(46.7)	—
Purchases of minerals in place (4)	0.2	0.7	—	0.8	2.7	—	12.1	19.9	0.1
Production	(18.8)	(103.2)	(7.9)	(13.7)	(123.0)	(10.3)	(16.6)	(146.9)	(14.2)
End of year	175.7	1,321.8	107.4	158.2	1,280.1	96.5	104.9	1,111.1	105.7
Proved developed reserves:									
Beginning of year	58.6	642.9	49.0	48.5	609.1	58.6	75.6	644.4	61.5
End of year	68.2	699.1	60.1	58.6	642.9	49.0	48.5	609.1	58.6
Proved undeveloped reserves:									
Beginning of year	99.6	637.2	47.6	56.4	502.0	47.1	69.6	619.7	53.9
End of year	107.6	622.7	47.2	99.6	637.2	47.6	56.4	502.0	47.1

Note: Amounts may not calculate due to rounding.

(1) 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 Half 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.

(2) 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.

(3) For the year ended December 31, 2016, the Company added 108.2 MMBOE from its drilling program and acquired 15.5 MMBOE. These additions were offset by net downward revisions of 96.2 MMBOE, consisting of 18.1 MMBOE of performance revisions, a 35.1 MMBOE price revision, and the removal of 43.0 MMBOE of proved undeveloped reserves to reflect the Company's shift to develop its predominately unproven Midland Basin properties. Additionally, the Company divested 47.7 MMBOE during 2016.

(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,		
	2018	2017	2016
Oil (per Bbl)	$57.76	$48.57	$37.22
Gas (per Mcf)	$3.49	$3.20	$2.45
NGLs (per Bbl)	$26.23	$23.33	$16.38

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,		
	2018	2017	2016
	(in thousands)		
Future cash inflows	$17,579,432	$14,035,704	$8,359,938
Future production costs	(5,386,264)	(5,594,226)	(4,634,649)
Future development costs	(2,679,488)	(2,638,459)	(1,636,077)
Future income taxes (1)	(1,012,209)	(205,694)	—
Future net cash flows	8,501,471	5,597,325	2,089,212
10 percent annual discount	(3,847,088)	(2,573,183)	(937,099)
Standardized measure of discounted future net cash flows	$4,654,383	$3,024,142	$1,152,113

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(1) Regarding the calculations as of December 31, 2016, after evaluating all factors and giving effect to tax basis, future tax deductions, and available tax credits, the Company determined that at price levels for each respective period, future net cash flows would not be subject to federal or state income tax for the projected life of the reserves under authoritative tax legislation.

The principle sources of changes in the Standardized Measure were:

	For the Years Ended December 31,		
	2018	2017	2016
	(in thousands)		
Standardized Measure, beginning of year	$3,024,142	$1,152,113	$1,790,526
Sales of oil, gas, and NGLs produced, net of production costs	(1,148,991)	(745,877)	(580,861)
Net changes in prices and production costs	1,010,335	1,181,447	(315,725)
Extensions, discoveries and other including infill reserves in an existing proved field, net of related costs	2,218,475	1,638,734	242,556
Sales of reserves in place	(147,887)	(226,528)	(377,607)
Purchase of reserves in place	1,818	12,032	115,270
Previously estimated development costs incurred during the period	445,638	121,879	290,837
Changes in estimated future development costs	(34,871)	(116,609)	27,961
Revisions of previous quantity estimates	(611,168)	103,916	(124,845)
Accretion of discount	305,657	115,211	179,050
Net change in income taxes	(449,884)	(32,426)	—
Changes in timing and other	41,119	(179,750)	(95,049)

Standardized Measure, end of year	$4,654,383	$3,024,142	$1,152,113

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Quarterly Financial Information (unaudited)

The Company's quarterly financial information for fiscal years 2018 and 2017 is as follows (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
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 [1]	$2.84	$0.15	$(1.21)	$2.76
Diluted net income (loss) per common share [1]	$2.81	$0.15	$(1.21)	$2.73
Dividends declared per common share	$0.05	$—	$0.05	$—
Year Ended December 31, 2017 [3]				
Total operating revenues and other income	$372,738	$120,721	$295,379	$340,538
Total operating expenses [4]	206,577	268,047	380,531	437,942
Income (loss) from operations [4]	$166,161	$(147,326)	$(85,152)	$(97,404)
Income (loss) before income taxes	$118,940	$(190,968)	$(128,382)	$(143,403)
Net income (loss)	$74,434	$(119,907)	$(89,112)	$(26,258)
Basic net income (loss) per common share [1]	$0.67	$(1.08)	$(0.80)	$(0.24)
Diluted net income (loss) per common share [1]	$0.67	$(1.08)	$(0.80)	$(0.24)
Dividends declared per common share	$0.05	$—	$0.05	$—

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(1) Amounts may not calculate due to rounding.

(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 previously held for sale. 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 (see 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 (see 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, respectively (see Note 10 – Derivative Financial Instruments).

(3) During the first quarter of 2017, the Company recorded an estimated $37.5 million net pre-tax gain on divestiture activity related to the sale of the Company's outside-operated Eagle Ford shale assets partially offset by a write-down of the Company's Divide County, North Dakota assets, which were previously classified as held for sale. During the second quarter of 2017, the Company recorded a $167.1 million net pre-tax loss on divestiture activity related primarily to an additional write-down of the Company's retained Divide County, North Dakota assets upon reclassification as assets held for use. For the first, second, third, and fourth quarters of 2017, the Company recorded a $114.8 million net derivative gain, a $55.2 million net derivative gain, an $80.6 million net derivative loss, and a $115.8 million net derivative loss, respectively (see Note 10 – Derivative Financial Instruments).

(4) Amounts have been adjusted to conform to the current period presentation on the consolidated financial statements. Please refer to Recently Issued Accounting Standards in Note 1 – Summary of Significant Accounting Policies for additional discussion.

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 the Chief Executive Officer and the 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 the 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 these 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 2018 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, 2018. 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, 2018.

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, 2018, 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, 2018, 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, 2018 and 2017, 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, 2018, and the related notes and our report dated February 21, 2019 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 21, 2019

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 2019 annual meeting of stockholders to be filed within 120 days from December 31, 2018.

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 2019 annual meeting of stockholders to be filed within 120 days from December 31, 2018.

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 2019 annual meeting of stockholders to be filed within 120 days from December 31, 2018.

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 2019 annual meeting of stockholders to be filed within 120 days from December 31, 2018.

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. See Note 7 – Compensation Plans included 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, 2018:

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			
Stock options and incentive stock options (1)	—	$ —	
Restricted stock units (1)(2)	1,251,957	N/A	
Performance share units (1)(2)(3)	1,725,044	N/A	
Total for Equity Incentive Compensation Plan	2,977,001	$ —	5,877,607
Employee Stock Purchase Plan (4)	—	—	1,613,871
Equity compensation plans not approved by security holders	—	—	—
Total for all plans	2,977,001	$ —	7,491,478

(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 2018, 2017, and 2016 under the Equity Plan were 1,220,217, 2,078,878, and 918,509, 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 $21.49 and $20.68, respectively. Please refer to Note 7 – Compensation Plans in Part II, Item 8 of this report for additional discussion.

(3) The number of awards vested 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 2018, 2017, and 2016 under the ESPP were 199,464, 186,665, and 218,135, 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 2019 annual meeting of stockholders to be filed within 120 days from December 31, 2018.

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 Preapproval Policy and Procedures" in the Company's definitive proxy statement for the 2019 annual meeting of stockholders to be filed within 120 days from December 31, 2018.

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 August 8, 2016 between SM Energy Company and Rock Oil Holdings LLC (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on August 8, 2016, and incorporated herein by reference)
2.2	Purchase and Sale Agreement, dated October 17, 2016, by and between SM Energy Company and QStar LLC (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on October 21, 2016, and incorporated herein by reference)
2.3	Letter Agreement dated October 17, 2016, by and among SM Energy Company, QStar LLC, and RRP-QStar, LLC (filed as Exhibit 2.2 to the registrant's Current Report on Form 8-K filed on October 21, 2016, and incorporated herein by reference)
2.4	Purchase and Sale Agreement dated October 17, 2016, by and between SM Energy Company and Oasis Petroleum North America LLC (filed as Exhibit 2.3 to the registrant's Current Report on Form 8-K filed on October 21, 2016, and incorporated herein by reference)
2.5	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)
2.6	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)
2.7	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	Lock-Up and Registration Rights Agreement, dated December 21, 2016, by and among SM Energy Company, QStar LLC and RRP-QStar, LLC (filed as Exhibit 4.13 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2016, and incorporated herein by reference)
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†	Performance Stock Unit Award Agreement as of July 1, 2016 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, and incorporated herein by reference)
10.15†	Restricted Stock Unit Award Agreement as of July 1, 2016 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, and incorporated herein by reference)
10.16†	Non-Employee Director Restricted Stock Award Agreement as of May 25, 2016 (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, and incorporated herein by reference)
10.17†	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)
10.18†	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)
10.19†	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)
10.20*†	Summary of Compensation Arrangements for Non-Employee Directors
10.21	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)
10.22†	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)
10.23†	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)
10.24***	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)
10.25	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)
10.26	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)
10.27	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)
10.28	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)
10.29	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)
10.30	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)
10.31	

	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)
10.32†	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)
10.33†	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)
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*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

* 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. See Item 15(a) above.

ITEM 16. FORM 10-K SUMMARY

None.

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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 21, 2019 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, 2018, 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 21, 2019
/s/ A. WADE PURSELL A. Wade Pursell	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 21, 2019
/s/ PATRICK A. LYTLE Patrick A. Lytle	Controller and Assistant Secretary (Principal Accounting Officer)	February 21, 2019

Signature	Title	Date
/s/ WILLIAM D. SULLIVAN William D. Sullivan	Chairman of the Board of Directors	February 21, 2019
/s/ CARLA J. BAILO Carla J. Bailo	Director	February 21, 2019
/s/ LARRY W. BICKLE Larry W. Bickle	Director	February 21, 2019
/s/ STEPHEN R. BRAND Stephen R. Brand	Director	February 21, 2019
/s/ LOREN M. LEIKER Loren M. Leiker	Director	February 21, 2019
/s/ RAMIRO G. PERU Ramiro G. Peru	Director	February 21, 2019
/s/ JULIO M. QUINTANA Julio M. Quintana	Director	February 21, 2019
/s/ ROSE M. ROBESON Rose M. Robeson	Director	February 21, 2019