SM Energy Co
Form 10-K
February 21, 2018

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, 2017
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. Yesþ Noo

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yesþ Noo

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

(Do not check if a smaller reporting company)

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 110,439,354 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 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, of $16.53 per share, as reported on the New York Stock Exchange, was $1,825,562,522. 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 14, 2018, the registrant had 111,687,016 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 2018 annual meeting of stockholders to be filed within 120 days after December 31, 2017.

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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 acquisition, exploration, development, and production 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 offices are 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 seek to maximize the value of our assets through industry-leading technology and outstanding operational execution. We focus on achieving high full-cycle economic returns on our investments and maintaining a strong balance sheet.

Significant Developments in 2017

Reserves and Capital Investment. Our estimated proved reserves increased 18 percent to 468.1 MMBOE at December 31, 2017, from 395.8 MMBOE at December 31, 2016. We had net reserve additions of 191.6 MMBOE primarily as a result of our successful development programs and completion optimizations that resulted in improved well performance. These positive results were partially offset by the divestiture of 76.0 MMBOE of estimated proved reserves, primarily associated with the sale of our outside-operated Eagle Ford shale assets as further discussed below. Costs incurred for development and exploration activities, excluding acquisitions, increased 33 percent to $947.0 million in 2017 when compared with 2016. Our proved reserve life index increased significantly to 10.5 years in 2017 compared to 7.2 years in 2016. 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.

Divestiture Activity. On March 10, 2017, we successfully completed the divestiture of our outside-operated Eagle Ford shale assets, including our ownership interest in related midstream assets, for net divestiture proceeds of $744.1 million and a final net gain of $396.8 million. We also divested certain non-core properties in our Rocky Mountain and Permian regions for net divestiture proceeds of $36.2 million during 2017. As of December 31, 2017, the majority of our Powder River Basin assets were classified as held for sale. Subsequent to December 31, 2017, we entered into a definitive agreement for the sale of these assets for a gross purchase price of $500.0 million, subject to customary closing price adjustments (the "PRB Divestiture"). The PRB Divestiture is expected to close in the first quarter of 2018 and is subject to satisfying customary closing conditions. There can be no assurance that the PRB Divestiture will close on time or at all.

Acquisition Activity. During 2017, we finalized the 2016 acquisitions from Rock Oil Holdings, LLC and from QStar LLC and RRP-QStar, LLC of Midland Basin properties located in Howard and Martin Counties, Texas (collectively referred to as our "RockStar" assets throughout this report). In addition to the acreage we acquired in the RockStar acquisitions, we also continued to core up our position in Howard and Martin Counties, Texas during 2017 by acquiring approximately 3,600 net acres of primarily unproved properties for $76.5 million of cash consideration, as well as completing numerous non-monetary acreage trades. Through these efforts we continue to improve our ability to drill longer lateral wells and generate higher returns.

Production. Our average daily production in 2017 consisted of 37.4 MBbl of oil, 337.0 MMcf of gas, and 28.2 MBbl of NGLs, for an average equivalent production rate of 121.8 MBOE per day, which represents a 19 percent decrease on an equivalent basis compared with 2016. This decrease in production was driven by the divestiture of our outside-operated Eagle Ford shale assets in the first quarter of 2017, the divestiture of our Williston Basin assets outside of Divide County, North Dakota (referred to as “Raven/Bear Den” throughout this report) in the fourth quarter of 2016, and reduced capital investment in our retained Rocky Mountain and Eagle Ford shale programs in 2017, when compared with 2016. These decreases were partially offset by increased production in our Permian region as a result of ramping up development activities on our acquired acreage and stronger than expected well results. When excluding production from all assets sold in 2016 and 2017, production from retained assets and assets acquired increased approximately eight percent for the year ended December 31, 2017, compared with 2016. Please refer to Areas of Operation below for additional discussion.

Outlook for 2018

Our priorities for 2018 are to:

- continue generating high margin returns from top tier projects that drive cash flow growth;
- core up our portfolio (PRB Divestiture) to focus on assets that generate the highest returns; and
- improve our credit metrics and maintain strong financial flexibility.

Our capital program for 2018, excluding acquisitions, is expected to be approximately $1.27 billion. We expect our program to concentrate on developing our top tier assets in the Midland Basin and Eagle Ford shale. We expect to allocate the majority of our 2018 capital to our Midland Basin program, which generates the highest margins and returns 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 previously announced joint venture agreement. We will continue to prioritize safety in all of our operations. Please refer to Outlook for 2018 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 2018.

Areas of Operation

Our 2017 operations were concentrated in our three onshore operating regions in the United States. The following table summarizes estimated proved reserves, production, and costs incurred in oil and gas activities for the year ended December 31, 2017, for these regions:

	Permian	South Texas & Gulf Coast	Rocky Mountain	Total [1]
Proved reserves				
Oil (MMBbl)	117.5	13.3	27.4	158.2
Gas (Bcf)	252.8	998.1	29.2	1,280.1
NGLs (MMBbl)	0.2	95.6	0.7	96.5
MMBOE [1][2]	159.9	275.2	33.0	468.1
Relative percentage	34 %	59 %	7 %	100 %
Proved developed %	34 %	52 %	53 %	46 %
Production				
Oil (MMBbl)	8.5	2.0	3.2	13.7
Gas (Bcf)	14.7	104.2	4.1	123.0
NGLs (MMBbl)	—	10.1	0.2	10.3
MMBOE [1][2]	11.0	29.5	4.1	44.5
Avg. daily equivalents (MBOE/d) [1]	30.0	80.7	11.1	121.8
Relative percentage	25 %	66 %	9 %	100 %
Costs incurred (in millions)[3]	$831.4	$170.3	$ 19.5	$1,040.0

(1) Amounts may not calculate due to rounding.

(2) As of December 31, 2017, a majority of our Powder River Basin assets were held for sale, and subsequent to December 31, 2017, we entered into the PRB Divestiture agreement. These assets represented approximately 4.2 MMBOE of our estimated proved reserves as of December 31, 2017, and approximately 1.0 MMBOE of 2017 production on an equivalent basis. There can be no assurance that the PRB Divestiture will close on time or at all.

(3) Amounts do not sum to total costs incurred due primarily to corporate overhead charges incurred on exploration activity 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.

Excluding acquisition activity, we increased our capital spending in 2017 as we accelerated development activities in our Permian region, particularly on our RockStar properties. We had 191.6 MMBOE of net proved reserve additions during the year primarily as a result of our successful development efforts and improved well results in the Midland Basin and enhanced completion techniques in the Eagle Ford shale. These increases were partially offset by the divestiture of our outside-operated Eagle Ford shale assets and removal of proved undeveloped reserves due to the five-year rule as a result of changes in our development plans. Overall, total estimated proved reserves for year end 2017 increased 18 percent from year end 2016.

Permian Region. Operations in our Permian region are managed from our office in Midland, Texas. In 2017, we focused on delineating, developing, and coring up our approximately 85,000 net acre Midland Basin position in western Texas. Our acreage position provides for substantial future development opportunities within multiple oil-rich intervals, including the Spraberry and Wolfcamp formations.

We incurred $739.5 million of costs and added approximately 110.7 MMBOE of estimated proved reserves through our drilling and completion activities in 2017. The majority of our Midland Basin capital was deployed on projects targeting the Lower Spraberry and Wolfcamp A and B intervals on our RockStar assets in Howard and Martin Counties, Texas and Sweetie Peck assets in Upton and Midland Counties, Texas. We began 2017 with four operated drilling rigs and one completion crew and added four operated drilling rigs and three completion crews throughout the year. As of December 31, 2017, we had seven operated drilling rigs and three completion crews focused on delineating and developing our RockStar assets, and one operated drilling rig and one completion crew focused on developing our Sweetie Peck assets. Estimated

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proved reserves increased 197 percent to 159.9 MMBOE at year end 2017 from 53.8 MMBOE at year end 2016. We completed 72 gross (70 net) wells during 2017 and production increased 192 percent year-over-year to 11.0 MMBOE for 2017.

As of December 31, 2017, we had 49 gross (41 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 office in Houston, Texas. This region is primarily comprised of our Eagle Ford shale position, which includes approximately 163,000 net acres. Our largely contiguous acreage position covers a significant portion of the western Eagle Ford shale play, including acreage in the gas/condensate, NGL-rich gas, and dry gas windows of the play. We sold our outside-operated Eagle Ford shale assets, including the associated midstream assets, in the first quarter of 2017.

In 2017, we incurred $169.4 million of costs and added approximately 62.6 MMBOE of estimated proved reserves through our drilling and completion activities. Estimated proved reserves decreased 10 percent to 275.2 MMBOE at year end 2017 from 305.4 MMBOE at year end 2016. This decrease primarily related to the divestiture of 72.5 MMBOE from our outside-operated Eagle Ford shale assets and production of 29.5 MMBOE during the year. Offsetting the majority of these decreases were proved reserve additions as a result of our development activities and improved well performance on our retained Eagle Ford shale assets. We completed 38 gross (35 net) wells during 2017 on our operated acreage.

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. The third-party in this arrangement will carry substantially all drilling and completion costs and will be entitled to a majority of the associated production revenue until certain payout thresholds are reached. This partnership 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. The joint venture resulted in the completion of seven gross wells and the drilling of four gross wells in 2017. We expect the remaining wells associated with this joint venture to be drilled and completed in 2018.

As of December 31, 2017, we had 33 gross (30 net) wells that had been drilled but not completed in our operated Eagle Ford shale program.

Rocky Mountain Region. Operations in our Rocky Mountain region are managed from our corporate office in Denver, Colorado. As of December 31, 2017, we had approximately 119,000 net acres in Divide County, North Dakota, and approximately 139,000 net acres in the Powder River Basin in Wyoming, of which approximately 112,000 net acres were classified as held for sale as of December 31, 2017. Subsequent to December 31, 2017, we entered into the PRB Divestiture agreement for the sale of these assets for a gross purchase price of $500.0 million, subject to customary closing price adjustments. The PRB Divestiture is expected to close in the first quarter of 2018 and is subject to satisfying customary closing conditions. There can be no assurance that the PRB Divestiture will close on time or at all.

In 2017, we incurred $19.3 million of costs to add approximately 1.7 MMBOE of estimated proved reserves in our Rocky Mountain region through our drilling and completion activities. Total estimated proved reserves decreased 10 percent to 33.0 MMBOE at year end 2017 from 36.5 MMBOE at year end 2016. Production decreased 61 percent year-over-year to 4.1 MMBOE for 2017 primarily as a result of the divestiture of our Raven/Bear Den assets in the fourth quarter of 2016 and reduced capital investment on our retained Rocky Mountain assets during 2017. Current activities in our Powder River Basin program are under an acquisition and development funding agreement with a third-party in which our costs to drill and complete a specified number of initial wells are being carried by such party.

As of December 31, 2017, we had 18 gross (15 net) drilled but not completed wells in our operated Bakken/Three Forks program.

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, 2017. 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 $51.34 per Bbl for oil, $3.00 per MMBtu for gas, and $27.69 per Bbl for NGLs for the year ended December 31, 2017. We then adjust 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. 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, 2017, 2016, and 2015:

	As of December 31,		
	2017	2016	2015
Reserve data:			
Proved developed			
Oil (MMBbl)	58.6	48.5	75.6
Gas (Bcf)	642.9	609.1	644.4
NGLs (MMBbl)	49.0	58.6	61.5
MMBOE (1)	214.7	208.7	244.5
Proved undeveloped			
Oil (MMBbl)	99.6	56.4	69.6
Gas (Bcf)	637.2	502.0	619.7
NGLs (MMBbl)	47.6	47.1	53.9
MMBOE (1)	253.4	187.1	226.8
Total proved (1)			
Oil (MMBbl)	158.2	104.9	145.3
Gas (Bcf) (2)	1,280.1	1,111.1	1,264.0
NGLs (MMBbl)	96.5	105.7	115.4
MMBOE (3)	468.1	395.8	471.3
Proved developed reserves %	46 %	53 %	52 %
Proved undeveloped reserves %	54 %	47 %	48 %
Reserve data (in millions):			
Standardized measure of discounted future net cash flows (GAAP)	$3,024.1	$1,152.1	$1,790.5
PV-10 (non-GAAP):			
Proved developed PV-10	$1,984.2	$1,051.1	$1,593.0
Proved undeveloped PV-10	1,072.3	101.0	197.5
Total proved PV-10	$3,056.5	$1,152.1	$1,790.5
Reserve life index (years)	10.5	7.2	7.3

(1) Amounts may not calculate due to rounding.

(2) For the years ended December 31, 2017, 2016, and 2015, proved gas reserves contained 48.1 Bcf, 43.7 Bcf, and 48.1 Bcf of gas, respectively, that we expect to produce and use as field fuel (primarily for compressors).

(3) As of December 31, 2017, a majority of our Powder River Basin assets were held for sale, and subsequent to year end 2017, we entered into the PRB Divestiture agreement. These assets represented approximately 4.2 MMBOE of our total estimated proved reserves as of December 31, 2017. There can be no assurance that the PRB Divestiture will close on time or at all.

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,		
	2017	2016	2015
	(in millions)		
Standardized measure of discounted future net cash flows (GAAP)	$3,024.1	$1,152.1	$1,790.5
Add: 10 percent annual discount, net of income taxes	2,573.2	937.1	1,307.1
Add: future undiscounted income taxes	205.7	—	—
Undiscounted future net cash flows	5,803.0	2,089.2	3,097.6
Less: 10 percent annual discount without tax effect	(2,746.5)	(937.1)	(1,307.1)
PV-10 (non-GAAP)	$3,056.5	$1,152.1	$1,790.5

Proved Undeveloped Reserves

Proved undeveloped reserves include those 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. 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, 2017, we did not have any proved undeveloped reserves that had been on our books in excess of five years.

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 253.4 MMBOE of total proved undeveloped reserves as of December 31, 2017, approximately 66.8 MMBOE of proved undeveloped reserves in our Eagle Ford shale position, 49.3 MMBOE of proved undeveloped reserves in our Wolfcamp and Lower Spraberry shale positions in the Midland Basin, and 0.7 MMBOE of proved undeveloped reserves in our Bakken/Three Forks 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 significant 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, 2017, we had 253.4 MMBOE of estimated proved undeveloped reserves, which was an increase of 66.3 MMBOE, or 35 percent, from 187.1 MMBOE at December 31, 2016. The following table provides a reconciliation of our proved undeveloped reserves for the year ended December 31, 2017:

	Total (MMBOE)
Total proved undeveloped reserves:	
Beginning of year	187.1
Revisions of previous estimates	2.9
Additions from discoveries, extensions, and infill [1]	132.8
Sales of reserves [2]	(35.1)
Purchases of minerals in place	0.3
Removed for five-year rule [3]	(13.9)
Conversions to proved developed [4]	(20.7)
End of year [5]	253.4

(1) We added 132.4 MMBOE of infill proved undeveloped reserves, primarily from our Midland Basin and Eagle Ford shale programs, and an additional 0.4 MMBOE of proved undeveloped reserves through various extensions and discoveries. We added 76.7 MMBOE and 54.8 MMBOE of proved undeveloped reserves in our Midland Basin and Eagle Ford shale programs, respectively, in 2017.

(2) Sale of proved undeveloped reserves resulting from the divestiture of our outside-operated Eagle Ford shale assets during the first quarter of 2017.

(3) Proved undeveloped reserves were reduced by 13.9 MMBOE due to changes in our development plan, which caused these locations to be reclassified primarily to the probable reserves category due to the five-year rule. These locations, which were predominately located in our Eagle Ford shale program, were replaced by higher quality proved undeveloped reserves, which are classified as extensions or infills in the table above, and resulted from our testing and delineation programs.

(4) Conversions of proved undeveloped reserves to proved developed reserves were primarily in our Midland Basin and Eagle Ford shale programs. Our 2017 conversion track record was approximately 11 percent due to fewer conversions of proved undeveloped reserves in our Eagle Ford shale and Rocky Mountain programs as we focused on developing our Midland Basin assets, which had minimal proved undeveloped reserves booked at year end 2016. We expect our conversion track record to increase in 2018 as a result of increased capital expenditures related to converting proved undeveloped reserves added during 2017 in our Midland Basin program. During 2017, we incurred approximately $187 million on projects associated with reserves booked as proved undeveloped at the end of 2016, of which approximately $165 million was spent on proved undeveloped reserves converted to proved developed reserves by December 31, 2017. At December 31, 2017, drilled but not completed wells represented 31.0 MMBOE of total proved undeveloped reserves. We expect to incur approximately $193 million of capital expenditures in completing these drilled but not completed wells, and we expect all proved undeveloped reserves to be converted to proved developed reserves within five years from their initial booking as proved undeveloped reserves.

(5) As of December 31, 2017, 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 their targeted completion date.

As of December 31, 2017, estimated future development costs relating to our proved undeveloped reserves were approximately $554 million, $524 million, and $601 million in 2018, 2019, and 2020, 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 Business Development Director, subject to the oversight of our management and the Audit Committee of our Board of Directors, as discussed below. Our Corporate Business Development Director has over 25 years of experience in the energy industry, and holds a Bachelor of Science Degree in Petroleum Engineering from Montana Tech of the

University of Montana. He is also a member of the Society of Petroleum Engineers. Technical, geological, and engineering reviews of our assets are performed throughout the

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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 Business Development Director; 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 an Advising Senior Vice President who received a Bachelor of Science Degree in Chemical Engineering from Purdue University in 1979 and a Master of Science Degree in Chemical Engineering from the University of California, Berkeley in 1981. He is a licensed Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers, and the Society of Petroleum Evaluation Engineers. The Ryder Scott 2017 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 from time to time to discuss processes and findings.

Production

The following table summarizes the volumes and realized prices of oil, gas, and NGLs produced and sold from properties in which we held an interest during the periods indicated. 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,		
	2017	2016	2015
Net production volumes			
Oil (MMBbl)	13.7	16.6	19.2
Gas (Bcf)	123.0	146.9	173.6
NGLs (MMBbl)	10.3	14.2	16.1
Equivalent (MMBOE) (1)	44.5	55.3	64.2
Midland Basin net production volumes (2)			
Oil (MMBbl)	8.5	2.6	1.4
Gas (Bcf)	14.7	5.6	4.3
NGLs (MMBbl)	—	—	—
Equivalent (MMBOE) (1)	11.0	3.5	2.1
Eagle Ford net production volumes (2)(3)			
Oil (MMBbl)	1.9	5.4	7.6
Gas (Bcf)	104.0	129.9	147.2
NGLs (MMBbl)	10.1	13.8	15.6
Equivalent (MMBOE) (1)	29.3	40.9	47.7
Realized price, before the effect of derivative settlements			
Oil (per Bbl)	$47.88	$36.85	$41.49
Gas (per Mcf)	$3.00	$2.30	$2.57
NGLs (per Bbl)	$22.35	$16.16	$15.92
Per BOE	$28.20	$21.32	$23.36
Production expense per BOE			
Lease operating expense	$4.43	$3.51	$3.73
Transportation costs	$5.48	$6.16	$6.02
Production taxes	$1.18	$0.94	$1.13
Ad valorem tax expense	$0.34	$0.21	$0.39

(1) Amounts may not calculate due to rounding.

(2) As of December 31, 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 also exceeded 15 percent of our total estimated proved reserves expressed on an equivalent basis. During each of the annual periods presented, no other field exceeded 15 percent of our total estimated proved reserves 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, 9.7 MMBOE, and 12.0 MMBOE of net production on an equivalent basis for the years ended December 31, 2017, 2016, and 2015, respectively.

Productive Wells

As of December 31, 2017, we had working interests in 1,099 gross (919 net) productive oil wells and 497 gross (489 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, 2017, four 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.

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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 2017, 2016, and 2015, excluding non-consented projects, active injector wells, salt water disposal wells, and any wells in which we own only a royalty interest:

	For the Years Ended December 31,					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Oil	56	46.5	100	73.0	87	56.5
Gas	38	34.6	114	56.1	272	100.8
Non-productive	4	3.2	2	1.1	—	—
	98	84.3	216	130.2	359	157.3
Exploratory wells						
Oil	32	28.7	7	6.8	5	3.5
Gas	—	—	—	—	1	1.0
Non-productive	1	0.1	—	—	5	4.1
	33	28.8	7	6.8	11	8.6
Total	131	113.1	223	137.0	370	165.9

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 2017 (included in the table above), we were actively participating in the drilling of 32 gross (30.7 net) wells and had 103 gross (82.9 net) drilled but not completed wells as of January 31, 2018. These drilled but not completed wells represent wells that were being completed or were waiting on completion as of January 31, 2018.

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, 2017. 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	40,708	34,767	38,929	30,382	79,637	65,149
Sweetie Peck	14,888	14,042	894	771	15,782	14,813
Halff East	8,951	5,174	1,276	246	10,227	5,420
Midland Basin Total	64,547	53,983	41,099	31,399	105,646	85,382
Eagle Ford	70,708	70,126	96,332	92,727	167,040	162,853
Rocky Mountain:						
Divide	162,584	108,801	21,922	10,615	184,506	119,416
Powder River Basin (4)	52,773	41,840	120,547	96,704	173,320	138,544
Rocky Mountain Other (5)	—	—	254,744	186,845	254,744	186,845
Other (6)	16,279	11,368	16,991	15,298	33,270	26,666
Total	366,891	286,118	551,635	433,588	918,526	719,706

(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 presentation 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 14, 2018, approximately 17,900, 10,200, and 5,300 net acres of undeveloped acreage are scheduled to expire by December 31, 2018, 2019, and 2020, respectively, if production is not established or we take no other action to extend the terms of the applicable lease or leases.

(4) Approximately 112,000 net acres of our Powder River Basin acreage was held for sale as of December 31, 2017, and subsequent to December 31, 2017, we entered into the PRB Divestiture agreement. There can be no assurance that the PRB Divestiture will close on time or at all.

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

(6) Includes other non-core acreage.

Delivery Commitments

As of December 31, 2017, we had gathering, processing, transportation throughput, and delivery commitments with various third-parties that have aggregate minimum delivery commitments of 19 MMBbl of oil, 789 Bcf of gas, and 24 MMBbl of produced water through 2028. We are required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. If a shortfall in the minimum volume commitment for gas is projected, we have rights under certain contracts to arrange for third-party gas to be delivered, and such volumes will count toward our minimum volume commitment. Our current production is insufficient to offset these aggregate contractual liabilities, but we expect to fulfill the delivery commitments with production from the future development of our proved undeveloped reserves and from the future development of resources not yet characterized as proved reserves, or through arranging for the delivery of third-party gas. In the event that no more product is delivered in accordance with these agreements, the aggregate undiscounted future deficiency payments as of December 31, 2017, would total $463.4 million. Please refer to Note 6 – Commitments and Contingencies in Part II, Item 8 for additional discussion. As of the filing of this report, we do not expect any material shortfalls in our delivery 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 numerous purchasers are present 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,		
	2017	2016	2015
Major customer #1 (1)	10%	5 %	4 %
Major customer #2 (2)	7 %	18%	21%
Group #1 of entities under common ownership (3)	17%	15%	10%
Group #2 of entities under common ownership (3)	8 %	8 %	11%

(1) This major customer is a purchaser of a portion of our production from our Permian region.

(2) This major customer was the operator in our outside-operated Eagle Ford shale program, which we divested during the first quarter of 2017. Prior to the divestiture, we were party to various marketing agreements whereby we were subject to certain gathering, transportation, and processing throughput commitments. Because we shared with the operator the risk of non-performance by its counterparty purchasers, we included the operator as a major customer in the table above. Several of the operator's counterparty purchasers under these contracts were also direct purchasers of our production from other areas.

(3) In the aggregate, these groups of entities under common ownership represent more than 10 percent of total oil, gas, and NGL production revenue for at least one of the periods shown; however, none of the individual entities comprising either group represented more than 10 percent of our total oil, gas, and NGL production revenue.

Employees and Office Space

As of February 14, 2018, we had 635 full-time employees. This is a five percent increase from the 607 reported full-time employees as of February 15, 2017. None of our employees are subject to a collective bargaining agreement, and we consider our relations with our employees to be good.

The following table summarizes the approximate square footage of office space leased by us, as of December 31, 2017, including our corporate headquarters and regional offices:

	Approximate Square Footage Leased
Corporate	107,000
Permian	54,000
South Texas & Gulf Coast	70,000
Mid-Continent (1)	50,000
Total	281,000

(1) During the third quarter of 2015, we closed our office in Tulsa, Oklahoma. We have subleased this space through 2019, and our lease expires in 2022.

In addition to the leased office space summarized in the table above, we own 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

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properties. Most of our producing properties are subject to mortgages securing indebtedness under our Fifth Amended and Restated Credit Agreement, as amended (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 staffs 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 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

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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 of a

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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, United States Army Corps of Engineers, or analogous state agencies. 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, increased 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 level, 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 our 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 to 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 cooperated with other producers in North Dakota in the ongoing development of recommendations to reduce the amount of flaring that is occurring there as a result of area wide infrastructure limitations that are beyond our control. Another focus for our environmental effort has been reduction of water use through recycling of flowback water in south Texas for use as frac fluid. 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," "will," and similar expressions ar 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;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- the drilling of wells and other exploration and development activities and plans, 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, 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, and our outlook on our future financial condition or results of operations; 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 such factors as:

- 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 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;
- 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 and expertise of third-party service providers on our operated properties;
- 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 whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate (including any delay in our planned PRB Divestiture as a result of litigation);
- the uncertainties associated with enhanced recovery methods;
- our commodity derivative contracts 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 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 seasonal weather conditions 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 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 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. 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, butane, and natural gasolines 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 amount of our oil, gas, and NGL reserves. For example, the amount of our borrowing base under our Credit Agreement is subject to periodic redeterminations 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 2017 and Reserves within Part I, Items 1 and 2, Comparison of Financial Results and Trends Between 2017 and 2016 and Between 2016 and 2015 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;
- 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 for the acquisition, future oil, gas, and NGL prices, the ability to reasonably estimate or assess 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 and 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

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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.

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 we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration, operations 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, 2017, 54%, or 253.4 MMBOE, of our estimated proved reserves were proved undeveloped. In order to develop our proved undeveloped reserves, as of December 31, 2017, we estimate approximately $2.5 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 and 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, 2017, was estimated using calculated 12-month average sales prices of $51.34 per Bbl of oil (NYMEX WTI spot price), $3.00 per MMBtu of gas (NYMEX Henry Hub spot price), and $27.69 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 2017, our monthly average realized oil prices before the effect of derivative settlements were as high as $56.35 per Bbl and as low as $41.34 per Bbl, and were as high as $27.98 per Bbl and as low as $18.88 per Bbl for NGLs. For the same period, our monthly average realized gas prices, excluding the effect of derivative settlements, were as high as $3.42 per Mcf and as low as $2.54 per Mcf. 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.

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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 (including any delay in our planned PRB Divestiture as a result of litigation). 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 include:

- 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 14, 2018, that is scheduled to expire over the next three years, represents approximately eight percent of our total net undeveloped acreage as of December 31, 2017. 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 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, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

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

To mitigate a portion of the exposure to potentially adverse market changes in oil, gas, and NGL prices and the associated impact on cash flows, we have entered into various derivative contracts. Our derivative contracts in place include swap and collar arrangements for oil, and swap arrangements for gas and NGLs. As of December 31, 2017, we were in a net accrued liability position of $139.4 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

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- 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 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, 2017, we were contractually committed to deliver 19 MMBbl of oil, 789 Bcf of gas, and 24 MMBbl of produced water. These contracts expire at various dates through 2028. 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, 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. Unproved properties are evaluated at the lower of cost or fair market value. We incurred impairment of proved properties expense and impairment of unproved properties expense totaling $3.8 million and $12.3 million, respectively, during 2017, $354.6 million and $80.4 million, respectively, during 2016, and $468.7 million and $78.6 million, respectively, during 2015. We also incurred impairment of other property, plant, and equipment expense totaling $49.4 million during 2015. 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 $925 million, 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 $925 million, down from $1.2 billion at December 31, 2016. This reduction was primarily a result of the sale of our outside-operated Eagle Ford shale assets during the first quarter of 2017, as well as adjustments consistent with lower commodity prices. The next semi-annual redetermination date is scheduled for April 1, 2018. We expect this redetermination to result in an increase to our borrowing base as a result of the increase in our proved reserves at December 31, 2017. 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, 2017, we had $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 ("Senior Convertible Notes") that we issued on August 12, 2016. As of December 31, 2017, we had $344.6 million of long-term senior unsecured debt outstanding relating to our 6.50% Senior Notes due 2021 ("2021 Notes") that we issued on November 8, 2011; $561.8 million of long-term senior unsecured debt outstanding relating to our 6.125% Senior Notes due 2022 ("2022 Notes") that we issued on November 17, 2014; $395.0 million of long-term senior unsecured debt outstanding relating to our 6.50% Senior Notes due 2023 ("2023 Notes") that we issued on June 29, 2012; $500.0 million of long-term senior unsecured debt outstanding relating to our 5.0% Senior Notes due 2024 ("2024 Notes") 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 ("2025 Notes") that we issued on May 21, 2015; and $500.0 million of long-term senior unsecured debt outstanding relating to our 6.75% Senior Notes due 2026 ("2026 Notes") that we issued on September 12, 2016 (collectively, the 2021 Notes, 2022 Notes, 2023 Notes, 2024 Notes, 2025 Notes, and 2026 Notes are referred to as our "Senior Notes"); and no outstanding borrowings under our secured credit facility. 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 $924.8 million of available borrowing capacity under our secured credit facility, assuming the borrowing conditions will be met. Our long-term debt represented 55 percent of our total book capitalization as of December 31, 2017.

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 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

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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 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, as of the last day of each of the Company’s fiscal quarters, our (a) ratio of senior secured debt to 12-month trailing adjusted EBITDAX to be not more than 2.75 to 1.0; (b) adjusted current ratio to be not less than 1.0 to 1.0; and (c) ratio of 12-month trailing adjusted EBITDAX to interest expense to be not less than 2.0 to 1.0. Our Credit Agreement also requires us to comply with certain additional financial covenants, including requirements that we maintain certain levels of stockholders’ equity and limit our annual cash dividends to no more than $50 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 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.

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 shutdown, abandon, or relocate drilling

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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, 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 any 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, tribal, 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, 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, tribal, 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, tribal, and local environmental laws for noise 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.

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

Operations in certain of our regions, such as our Permian, South Texas, and Rocky Mountain regions, are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife or plant species. In certain areas on federal lands, 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, including in greater sage-grouse habitats during breeding and nesting seasons, within a certain distance of active raptor nests during fledging, and in big game winter or parturition ranges during winter or calving seasons, 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 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 in the Wolfcamp and Spraberry shale intervals in the Midland Basin, the Eagle Ford shale of south Texas, and the Bakken/Three Forks formations in North Dakota. 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 in which we operate, including Texas and Wyoming, 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 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 continue to be 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 currently 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 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. The judicial challenge to the ozone standard has been stayed while the EPA reviews the standard. 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 indicated in late 2017 that it will take comments on completely withdrawing the guidelines. 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.

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. Over the past year, several court cases have addressed aspects of hydraulic fracturing. In a case that could delay operations on public lands, a court in California held that the BLM 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 Bakken and Three Forks formations in North Dakota, where we have significant operations, produce gas as well as oil. Constraints in the current gas gathering and processing network in certain areas have resulted in some of that gas being flared instead of gathered, processed, and sold. In June 2014, the North Dakota Industrial Commission, North Dakota’s chief energy regulator, adopted a policy to reduce the volume of gas flared from oil wells in the Bakken and Three Forks formations. The Commission is requiring operators to develop gas capture plans that describe how much gas is expected to be produced, how it will be delivered to a processor, and where it will be processed. Production caps or penalties will be imposed on certain wells that cannot meet the capture goals. 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. A preliminary injunction sought by industry groups was denied in U.S. District Court and the regulation went into effect on January 17, 2017; however, on December 8, 2017, the BLM finalized a rule suspending or delaying many of the provisions of the regulation while it reviews the regulation. This suspension of the rule is being challenged in the courts. These capture requirements, and any similar future obligations in North Dakota or our other locations, 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 has 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 kinds of cases on 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. Recently, 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. While "carbon tax" legislation has been introduced in the Senate, the prospects for passage of such legislation are highly 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

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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.

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 others or by other interruptions.

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 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 contractual control 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, infrastructure or capacity constraints, and general economic conditions could adversely affect our ability to produce, gather, process, and transport oil, gas, and NGLs.

In particular, if drilling in the Midland Basin continues to be successful, the amount of oil, gas, and NGLs being produced by us and others could exceed the capacity of, and result in strains on, the various gathering and transportation systems, pipelines, processing facilities, and other infrastructure available in that area. It will be necessary for additional infrastructure, pipelines, gathering and transportation systems and processing facilities to be expanded, built, or developed to accommodate anticipated production from these areas. Certain processing, pipeline, and other gathering or transportation 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 permitting 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 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, tribal, and local government authorities. These third-parties may incur substantial costs in order to comply with existing 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 amounts we pay for 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 conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily and adversely affect our cash flows and results of operations.

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.
Our business could be negatively impacted by security threats, including cybersecurity threats, terrorism, armed conflict, and other disruptions.
As an oil, gas, and NGLs 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.
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. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.
The threat of terrorism and the impact of military and other action 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 operations. Energy assets might be specific targets of terrorist attacks. 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.
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, 2017, to February 14, 2018, the intraday trading prices per share of our common stock as reported by the New York Stock Exchange ranged from a low of $12.29 per share in August 2017 to a high of $36.77 per share in January 2017. 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:
- changes in oil, gas, or NGL prices;
- 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.

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.

On February 1, 2018, SPM NAM LLC, an affiliate of Schlumberger Limited, filed a lawsuit in the District Court of Harris County, Texas against us, asserting that we had breached certain transfer provisions of the Acquisition and Development Funding Agreement, dated as of August 2, 2016 (the “ADFA”), by and among us, SPM NAM LLC, and certain other Schlumberger affiliates (Schlumberger Technology Corporation, Smith International, Inc., M-I LLC, and Cameron International Corporation (collectively such affiliates, the “Schlumberger Affiliates”)), and seeking, among other declaratory and equitable relief, to rescind SPM NAM LLC’s previously granted consent, which would allow us to consummate our planned sale of the majority of our Powder River Basin assets. We filed a motion seeking the dismissal of SPM NAM LLC’s rescission claim on February 8, 2018, and filed our answer and counterclaims against SPM NAM LLC on February 16, 2018. In addition, we filed a motion seeking to join the Schlumberger Affiliates to the lawsuit on February 16, 2018.

We believe that we have complied with the provisions of the ADFA, strongly dispute SPM NAM LLC’s allegations, and plan to vigorously defend ourselves. As further explained in our motion to dismiss, we do not believe that the laws of the State of Texas permit SPM NAM LLC to rescind the previously granted consent and believe that pursuant to the terms of the ADFA, SPM NAM LLC waived any right it may have had to a rescission remedy. We do not expect that these claims will impact our ability to divest our Powder River Basin assets.

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." The following table presents the range of high and low intraday sales prices per share for the indicated quarterly periods in 2017 and 2016, as reported by the New York Stock Exchange:

Quarter Ended	High	Low
December 31, 2017	$23.09	$16.72
September 30, 2017	$19.32	$12.29
June 30, 2017	$25.22	$13.76
March 31, 2017	$36.77	$20.01
December 31, 2016	$43.09	$30.25
September 30, 2016	$40.39	$23.58
June 30, 2016	$35.60	$17.04
March 31, 2016	$20.65	$6.99

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning December 31, 2012, and ending on December 31, 2017, 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 14, 2018, 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 23,400.

Dividends. We have paid cash dividends to our stockholders every year since 1940. Annual dividends of $0.05 per share were paid in each of the years 1998 through 2004. Annual dividends of $0.10 per share were paid in each of the years 2005 through 2017. We expect our practice of paying dividends on our common stock to continue, although the payment and amount of future dividends will continue to depend on our earnings, cash flows, capital requirements, financial condition, and other factors, including the discretion of our Board of Directors. In addition, the payment of dividends is subject to covenants in our Credit Agreement that limit our annual dividend payment to no more than $50.0 million per year. We are also subject to certain covenants under the indentures governing our Senior Notes and Senior Convertible Notes that restrict certain payments, including dividends; however, the first $6.5 million of dividends paid each year are not restricted by these covenants. Based on our current performance, we do not anticipate that these covenants will restrict future annual dividend payments in amounts not to exceed $0.10 per share of common stock. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $11.1 million, $7.8 million, and $6.8 million for the years ended December 31, 2017, 2016, and 2015, respectively.

Purchases of Equity Securities by the 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, 2017, 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)
01/01/2017 - 03/31/2017	379	$ 27.69	—	3,072,184
04/01/2017 - 06/30/2017	—	$ —	—	3,072,184
07/01/2017 - 09/30/2017	74,368	$ 16.52	—	3,072,184
10/01/2017 - 12/31/2017	—	$ —	—	3,072,184
Total	74,747	$ 16.57	—	3,072,184

(1) All shares purchased by us in 2017 were to offset tax withholding obligations that occurred upon the delivery of outstanding shares underlying RSUs delivered under the terms of grants under the Equity Incentive Compensation Plan ("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. Please refer to Dividends above for a description of our dividend limitations.

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 were 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,				
	2017	2016	2015	2014	2013
	(in millions, except per share data)				
Statement of operations data:					
Total operating revenues and other income	$1,129.4	$1,217.5	$1,557.0	$2,522.3	$2,293.4
Net income (loss)	$(160.8)	$(757.7)	$(447.7)	$666.1	$170.9
Net income (loss) per share:					
Basic	$(1.44)	$(9.90)	$(6.61)	$9.91	$2.57
Diluted	$(1.44)	$(9.90)	$(6.61)	$9.79	$2.51
Cash dividends declared and paid per common share	$0.10	$0.10	$0.10	$0.10	$0.10
Balance sheet data:					
Total assets	$6,176.8	$6,393.5	$5,621.6	$6,483.1	$4,678.1
Long-term debt:					
Revolving credit facility	$—	$—	$202.0	$166.0	$—
Senior Notes, net of unamortized deferred financing costs	$2,769.7	$2,766.7	$2,316.0	$2,166.4	$1,572.9
Senior Convertible Notes, net of unamortized discount and deferred financing costs	$139.1	$130.9	$—	$—	$—

Supplemental Selected Financial and Operations Data

	As of or for the Years Ended December 31,				
	2017	2016	2015	2014	2013
Balance sheet data (in millions):					
Total working capital (deficit)	$(10.1)	$(190.5)	$216.5	$(39.6)	$8.4
Total stockholders' equity	$2,394.6	$2,497.1	$1,852.4	$2,286.7	$1,606.8
Weighted-average common shares outstanding (in thousands):					
Basic	111,428	76,568	67,723	67,230	66,615
Diluted	111,428	76,568	67,723	68,044	67,998
Reserves:					
Oil (MMBbl)	158.2	104.9	145.3	169.7	126.6
Gas (Bcf)	1,280.1	1,111.1	1,264.0	1,466.5	1,189.3
NGLs (MMBbl)	96.5	105.7	115.4	133.5	103.9
MMBOE (1)	468.1	395.8	471.3	547.7	428.7
Production and operations (in millions):					
Oil, gas, and NGL production revenue	$1,253.8	$1,178.4	$1,499.9	$2,481.5	$2,199.6
Oil, gas, and NGL production expense	$507.9	$597.6	$723.6	$715.9	$597.0
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$557.0	$790.7	$921.0	$767.5	$822.9
General and administrative	$120.6	$126.4	$157.7	$167.1	$149.6
Production volumes:					
Oil (MMBbl)	13.7	16.6	19.2	16.7	13.9
Gas (Bcf)	123.0	146.9	173.6	152.9	149.3
NGLs (MMBbl)	10.3	14.2	16.1	13.0	9.5
MMBOE (1)	44.5	55.3	64.2	55.1	48.3
Realized price, before the effect of derivative settlements:					
Oil (per Bbl)	$47.88	$36.85	$41.49	$80.97	$91.19
Gas (per Mcf)	$3.00	$2.30	$2.57	$4.58	$3.93
NGLs (per Bbl)	$22.35	$16.16	$15.92	$33.34	$35.95
Expense per BOE:					
Lease operating expense	$4.43	$3.51	$3.73	$4.28	$4.49
Transportation costs	$5.48	$6.16	$6.02	$6.11	$5.34
Production taxes	$1.18	$0.94	$1.13	$2.13	$2.19
Ad valorem tax expense	$0.34	$0.21	$0.39	$0.46	$0.33
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$12.53	$14.30	$14.34	$13.92	$17.02
General and administrative	$2.71	$2.29	$2.46	$3.03	$3.09
Statement of cash flows data (in millions):					
Provided by operating activities (2)	$515.4	$552.8	$990.8	$1,456.6	$1,338.5
Used in investing activities (2)	$(201.5)	$(1,867.6)	$(1,144.6)	$(2,575.5)	$(1,183.0)
Provided by (used in) financing activities (2)	$(12.3)	$1,327.2	$153.7	$740.0	$130.7

(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 on the accompanying statements of cash flows 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. 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 prospective drilling opportunities, which we believe provide for long-term production and reserves growth. We focus on achieving high full-cycle economic returns on our investments and maintaining a strong balance sheet.

We currently have material core producing assets and acreage positions in the Midland Basin and Eagle Ford shale in Texas, as well as producing assets and material acreage positions in the Bakken/Three Forks play in North Dakota, and the Powder River Basin in Wyoming. The majority of our Powder River Basin assets were classified as held for sale as of December 31, 2017 and are expected to be sold in the first quarter of 2018. There can be no assurance that the PRB Divestiture will close on time or at all. During 2016, and continuing through 2017, we made several proved and unproved property acquisitions and acreage trades in the Midland Basin, while divesting non-core assets in other areas. By actively managing our asset portfolio in this way, we are seeking to concentrate our investments in areas with the highest economic returns and provide value through accelerated development activity.

2017 Financial and Operational Highlights

- We recorded a net loss of $160.8 million, or $1.44 per diluted share, for the year ended December 31, 2017. This compares with a net loss of $757.7 million, or $9.90 per diluted share, for the year ended December 31, 2016. Please refer to Comparison of Financial Results and Trends Between 2017 and 2016 and Between 2016 and 2015 below for additional discussion regarding the components of net loss for each period presented.
- At year end 2017, our estimated proved reserves totaled 468.1 MMBOE, of which 54 percent were liquids (oil and NGLs) and 46 percent were characterized as proved developed. During 2017, we added 175.0 MMBOE through our drilling program and acquired 1.3 MMBOE. We had positive revisions totaling 16.6 MMBOE, consisting of 23.1 MMBOE of price revisions due to increased commodity prices in 2017 and 7.4 MMBOE of positive performance revisions, offset by 13.9 MMBOE of proved undeveloped reserves removed due to the five year rule. Further, we divested of 76.0 MMBOE of proved reserves in 2017, which primarily related to our outside-operated Eagle Ford shale assets. Our proved reserve life index increased significantly to 10.5 years in 2017 compared to 7.2 years in 2016. 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 $3.0 billion as of December 31, 2017, compared with $1.2 billion as of December 31, 2016, which was an increase of 162 percent year-over-year. Please refer to Supplemental Oil and Gas Information in Part II, Item 8 of this report for additional discussion.
- We had net cash provided by operating activities of $515.4 million for the year ended December 31, 2017, compared with $552.8 million for the year ended December 31, 2016, which was a decrease of seven percent year-over-year. Please refer to Analysis of Cash Flow Changes Between 2017 and 2016 and Between 2016 and 2015 below for additional discussion.
- Adjusted EBITDAX, a non-GAAP financial measure, for the year ended December 31, 2017, was $664.7 million, compared with $790.8 million for the same period in 2016. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and a reconciliation of our net loss and net cash provided by operating activities to adjusted EBITDAX.

Operational Activities

During 2017, we focused on demonstrating the significant value potential of our Midland Basin position and cored-up this position to maximize long-term growth. Please refer to the table below that summarizes our operated drilling and completion activities for the year ended December 31, 2017.

In our Midland Basin program, we began 2017 operating four drilling rigs and one completion crew and added four drilling rigs and three completion crews throughout the year. Our operations during 2017 were focused on delineating and developing our RockStar acreage in Howard and Martin Counties, Texas, and developing our Sweetie Peck acreage position in Upton and Midland Counties, Texas. In both areas, we were targeting the Lower Spraberry and Wolfcamp A and B intervals. We completed 72 gross (70 net) operated wells during 2017 and increased production year-over-year by 192 percent to 11.0 MMBOE. Approximately 80 percent of our total 2017 capital was dedicated to coring up and developing our Midland Basin position.

In our operated Eagle Ford shale program, we added one operated drilling rig and one completion crew early in the first quarter of 2017. We added a second operated drilling rig in the third quarter. We completed 38 gross (35 net) wells on our operated acreage during 2017. Total operated and outside-operated Eagle Ford shale production was 29.3 MMBOE for 2017, a 28 percent decrease from 2016. The decrease in production from our Eagle Ford program was primarily driven by the sale of our outside-operated assets in the first quarter of 2017 and reduced capital investment on our operated acreage. Our focus in 2017 was on drilling and completion optimization and satisfying certain lease obligations. Approximately 16 percent of our 2017 capital program was dedicated to our Eagle Ford shale program.

During the third quarter of 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. This joint venture 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 our economic drilling inventory and acreage value. In 2017, this joint venture resulted in the completion of seven gross wells, in which our working interest was reduced in accordance with the terms of the joint venture agreement, and the drilling of four gross wells. We expect the remaining wells associated with the joint venture to be drilled and completed in 2018.

In our Powder River Basin program, we operated one drilling rig and one completion crew during 2017. All development activity in 2017 was performed under an acquisition and development funding agreement with a third-party, pursuant to which the third-party carried all of our drilling and completion costs for the year. Strong well results and successful delineation efforts were key to our recent announcement of the agreement to sell these assets for a gross purchase price of $500.0 million, subject to customary closing price adjustments. We expect the sale of these assets to close in the first quarter of 2018, but there can be no assurance it will close on time or at all.

2017 activity in our Bakken/Three Forks program in Divide County, North Dakota, was limited to the completion of two wells that had been previously drilled. We expected to divest of these properties at the beginning of 2017 but offers submitted in the sales process did not reach our expectations. As a result, we elected in the second quarter of 2017 to retain these assets and leverage the cash flows they generate to fund other projects in our Midland Basin and Eagle Ford shale programs.

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 during the year ended December 31, 2017.

	Midland Basin		Eagle Ford Shale		Bakken/Three Forks		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled but not completed at December 31, 2016	17	17	47	47	20	17	84	81
Wells drilled	104	94	27	24	—	—	131	118
Wells completed	(72)	(70)	(38)	(35)	(2)	(2)	(112)	(107)
Other [(1)]	—	—	(3)	(6)	—	—	(3)	(6)
Wells drilled but not completed at December 31, 2017	49	41	33	30	18	15	100	86

(1)

Reflects net working interest changes resulting from the Eagle Ford North joint venture agreement discussed above, as well as three previously drilled wells that we no longer intend to complete.

Production Results

The table below provides a regional breakdown of our production for the year ended December 31, 2017:

	Permian	South Texas & Gulf Coast	Rocky Mountain	Total [1]
Production:				
Oil (MMBbl)	8.5	2.0	3.2	13.7
Gas (Bcf)	14.7	104.2	4.1	123.0
NGLs (MMBbl)	—	10.1	0.2	10.3
Equivalent (MMBOE) [1]	11.0	29.5	4.1	44.5
Avg. Daily Equivalents (MBOE/d)	30.0	80.7	11.1	121.8
Relative percentage	25 %	66 %	9 %	100 %

(1) Amounts may not calculate due to rounding.

Production on an equivalent basis decreased by 20 percent for the year ended December 31, 2017, compared with the same period in 2016. Production declines were primarily a result of property divestitures, which occurred in the last half of 2016 and the first quarter of 2017, specifically our Raven/Bear Den and outside-operated Eagle Ford shale asset divestitures. These declines were partially offset by increased production in our Permian region. When excluding production from all assets sold in 2016 and 2017, production from retained and acquired assets increased approximately eight percent for the year ended December 31, 2017, compared with the same period in 2016, driven primarily by the ramp up in our Midland Basin development program. Please refer to Comparison of Financial Results and Trends Between 2017 and 2016 and Between 2016 and 2015 and A Year-to-Year Overview of Selected Production and Financial Information, Including Trends below for additional discussion on production.

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, 2017 (in millions)
Development costs	$ 675.5
Exploration costs	271.5
Acquisitions	
Proved properties	1.6
Unproved properties	91.4
Total, including asset retirement obligations [1]	$ 1,040.0

(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.

The majority of our development costs were incurred in our Midland Basin and operated Eagle Ford shale programs for the year ended December 31, 2017. Exploration costs were primarily incurred in our Midland Basin program as we focused on delineating and optimizing the development of our undeveloped acreage in Howard and Martin Counties, Texas. Please refer to Operational Activities above for additional information on our regional activities.

Acquisition Activity

- We 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. We also completed several non-monetary acreage trades in Howard and Martin Counties, Texas, that are excluded from the costs incurred table presented above.

- During 2017, we finalized the 2016 acquisitions of Midland Basin properties from Rock Oil Holdings, LLC and from QStar LLC and RRP-QStar, LLC by paying additional cash consideration of $7.7 million and $7.3 million, respectively.

Divestiture Activity

- On March 10, 2017, we divested our outside-operated Eagle Ford shale assets, including our ownership interest in related midstream assets, for net divestiture proceeds of $744.1 million and a final net gain of $396.8 million.
- During 2017, we divested certain non-core properties in our Rocky Mountain and Permian regions for net divestiture proceeds of $36.2 million.
- During the second quarter of 2017, we made the decision to retain our Divide County, North Dakota assets previously held for sale, as offers submitted in the sales process did not reach our expectations. During the year ended December 31, 2017, we recorded a $526.5 million write-down on these assets.
- As of December 31, 2017, the majority of our Powder River Basin assets were classified as held for sale. Subsequent to year end, we executed a definitive sales agreement related to these assets for a gross purchase price of $500.0 million, subject to customary closing price adjustments. We expect the sale of these assets to close in the first quarter of 2018, but there can be no assurance it will close on time or at all.

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. We sell the majority of our gas under contracts using first-of-the-month index pricing, which means gas produced in a given month is sold at the first-of-the-month price regardless of the spot price on the day the gas is produced. For assets where high Btu gas is sold at the wellhead, we also receive additional value for the higher energy content contained in the gas stream. Our NGL production is generally sold using contracts paying us a monthly average of the posted OPIS daily settlement prices, adjusted for processing, transportation, and location differentials. Our oil is sold using the calendar month average of the NYMEX WTI daily contract settlement prices during the month of production, adjusted for quality, transportation, American Petroleum Institute (“API”) gravity, and location differentials. 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, 2017, 2016, and 2015:

	For the Years Ended December 31,		
	2017	2016	2015
Oil (per Bbl):			
Average NYMEX contract monthly price	$50.95	$43.32	$48.68
Realized price, before the effect of derivative settlements	$47.88	$36.85	$41.49
Effect of oil derivative settlements	$(2.28)	$14.63	$18.85
Gas:			
Average NYMEX monthly settle price (per MMBtu)	$3.11	$2.46	$2.61
Realized price, before the effect of derivative settlements (per Mcf)	$3.00	$2.30	$2.57
Effect of gas derivative settlements (per Mcf) (1)	$0.72	$0.64	$0.71
NGLs (per Bbl):			
Average OPIS price (2)	$27.63	$19.98	$19.76
Realized price, before the effect of derivative settlements	$22.35	$16.16	$15.92
Effect of NGL derivative settlements	$(3.44)	$(0.60)	$1.69

(1) Gas derivative settlements for the year ended December 31, 2015, included $15.3 million of early settlements of futures contracts as a result of divesting assets in our Mid-Continent region. These early settlements increased the effect of derivative settlements by $0.09 per Mcf for the year ended December 31, 2015.

(2) 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, gas, 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. Oil markets have strengthened due to recent inventory drawdowns, but we expect oil prices to remain volatile due to uncertainty in global demand and easy access to new supply such as increases in oil production from United States shale. Oil prices began to increase at the end of 2017 as a result of the Organization of Petroleum Exporting Countries (“OPEC”) and several non-OPEC exporting countries agreeing to maintain previously agreed upon production cuts through 2018.

Gas pricing has improved over the last year, largely as a result of demand growth from gas fired power generation, gas exports to Mexico, and liquefied natural gas (“LNG”) exports. We expect prices to remain near current levels in the near term as drilling rigs in operation increased during 2017 and into 2018 leading to increased supply. We also expect prices to fluctuate with changes in demand resulting from the weather.

NGL prices have also improved over the last year due to oil and gas price recovery, increased exports of ethane and propane, and new processing plants. 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 14, 2018, and December 31, 2017:

	As of February 14, 2018	As of December 31, 2017
NYMEX WTI oil (per Bbl)	$ 58.72	$ 59.62
NYMEX Henry Hub gas (per MMBtu)	$ 2.77	$ 2.83
OPIS NGLs (per Bbl)	$ 27.30	$ 30.82

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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 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 prices while also setting a price floor for a portion of our oil 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 for 2018

Our priorities for 2018, are to:

- continue generating high margin returns from top tier projects that drive cash flow growth;
- core up our portfolio (PRB Divestiture) to focus on assets that generate the highest returns; and
- improve our credit metrics and maintain strong financial flexibility.

Our capital program for 2018, excluding acquisitions, is expected to be approximately $1.27 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 the majority of our 2018 capital to our Midland Basin program, which generates the highest margins and returns 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 previously announced joint venture agreement. By concentrating our capital on the highest return programs 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 Midland Basin program, we entered 2018 operating eight drilling rigs and four completion crews and anticipate maintaining this level of activity on average throughout the remainder of the year. We plan to drill approximately 150 gross (130 net) wells and plan to complete approximately 125 gross (100 net) wells in 2018, the majority of which we will operate. In 2018, 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 operated Eagle Ford shale program, we entered 2018 operating two drilling rigs and one completion crew. We plan to run one to two operated drilling rigs and one to two completion crews throughout the remainder of 2018. We plan to drill approximately 33 gross (17 net) wells and plan to complete approximately 39 gross (25 net) wells in 2018. We expect our previously announced joint venture in a portion of our Eagle Ford North area will allow for an increase in our capital efficiency. This joint venture allows us to test new technologies and completion designs at varied well spacing on a portion of our acreage that does not currently generate substantial cash flows, potentially enhancing the asset’s value while reducing our required capital outlay for acreage holding.

We intend to run one operated drilling rig in our Powder River Basin program until we complete our PRB Divestiture. Our activity in the Powder River Basin through the closing of the divestiture is expected to be funded under an acquisition and development funding agreement with a third-party, in which the third-party is carrying our drilling and completion costs. After the completion of this divestiture, we do not intend to run a drilling rig or completion crew on our remaining Powder River Basin acreage. There can be no assurance that the PRB Divestiture will close on time or at all.

Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our 2018 capital program.

We expect our net income (loss) in our 2018 consolidated statement of operations to be significantly affected as a result of tax reform enacted during the fourth quarter of 2017. Please refer to Comparison of Financial Results and Trends Between December 31, 2017 and 2016 and Between 2016 and 2015, Overview of Liquidity and Capital Resources, and Critical Accounting Policies and Estimates below, as well as Note 4 – Income Taxes in Part II, Item 8 of this report for further discussion.

Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information for the quarter ended December 31, 2017, and the immediately preceding three quarters. A detailed discussion follows.

	For the Three Months Ended			
	December 31, 2017	September 30, 2017	June 30, 2017	March 31, 2017
	(in millions)			
Production (MMBOE)	10.4	10.7	11.3	12.1
Oil, gas, and NGL production revenue	$341.2	$ 294.5	$284.9	$333.2
Oil, gas, and NGL production expense	$122.8	$ 122.7	$124.4	$138.0
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$131.4	$ 134.6	$153.2	$137.8
Exploration	$16.9	$ 14.2	$13.1	$12.0
General and administrative	$35.0	$ 27.9	$28.5	$29.2
Net income (loss)	$(26.3)	$ (89.1)	$(119.9)	$74.4

Note: Amounts may not calculate due to rounding.

Selected Performance Metrics

	For the Three Months Ended			
	December 31, 2017	September 30, 2017	June 30, 2017	March 31, 2017
Average net daily production equivalent (MBOE per day)	112.6	116.0	124.6	134.4
Lease operating expense (per BOE)	$5.10	$4.81	$4.11	$3.82
Transportation costs (per BOE)	$5.01	$5.24	$5.71	$5.88
Production taxes as a percent of oil, gas, and NGL production revenue	4.3 %	4.2 %	4.0 %	4.2 %
Ad valorem tax expense (per BOE)	$0.33	$0.29	$0.16	$0.55
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$12.69	$12.61	$13.52	$11.39
General and administrative (per BOE)	$3.38	$2.61	$2.51	$2.42

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	
	2017	2016	2015	2017/2016	2016/2015	2017/2016	2016/2015
Net production volumes (1)							
Oil (MMBbl)	13.7	16.6	19.2	(2.9)	(2.6)	(18)%	(14)%
Gas (Bcf)	123.0	146.9	173.6	(23.9)	(26.7)	(16)%	(15)%
NGLs (MMBbl)	10.3	14.2	16.1	(3.9)	(1.9)	(27)%	(12)%
Equivalent (MMBOE)	44.5	55.3	64.2	(10.8)	(8.9)	(20)%	(14)%
Average net daily production (1)							
Oil (MBbl per day)	37.4	45.4	52.7	(7.9)	(7.3)	(17)%	(14)%
Gas (MMcf per day)	337.0	401.5	475.7	(64.5)	(74.2)	(16)%	(16)%
NGLs (MBbl per day)	28.2	38.8	44.0	(10.6)	(5.2)	(27)%	(12)%
Equivalent (MBOE per day)	121.8	151.0	175.9	(29.2)	(24.9)	(19)%	(14)%
Oil, gas, and NGL production revenue (in millions)							
Oil production revenue	$654.3	$611.8	$797.3	$42.5	$(185.5)	7 %	(23)%
Gas production revenue	369.4	337.3	447.0	32.1	(109.7)	10 %	(25)%
NGL production revenue	230.1	229.3	255.6	0.8	(26.3)	— %	(10)%
Total	$1,253.8	$1,178.4	$1,499.9	$75.4	$(321.5)	6 %	(21)%
Oil, gas, and NGL production expense							

(in millions)							
Lease operating expense	$196.9	$194.0	$239.6	$2.9	$(45.6)	1 %	(19)%
Transportation costs	243.6	340.3	386.6	(96.7)	(46.3)	(28)%	(12)%
Production taxes	52.4	51.9	72.4	0.5	(20.5)	1 %	(28)%
Ad valorem tax expense	15.0	11.4	25.0	3.6	(13.6)	32 %	(54)%
Total	$507.9	$597.6	$723.6	$(89.7)	$(126.0)	(15)%	(17)%
Realized price, before the effect of derivative settlements							
Oil (per Bbl)	$47.88	$36.85	$41.49	$11.03	$(4.64)	30 %	(11)%
Gas (per Mcf)	$3.00	$2.30	$2.57	$0.70	$(0.27)	30 %	(11)%
NGLs (per Bbl)	$22.35	$16.16	$15.92	$6.19	$0.24	38 %	2 %
Per BOE	$28.20	$21.32	$23.36	$6.88	$(2.04)	32 %	(9)%
Per BOE data							
Production expense:							
Lease operating expense	$4.43	$3.51	$3.73	$0.92	$(0.22)	26 %	(6)%
Transportation costs	$5.48	$6.16	$6.02	$(0.68)	$0.14	(11)%	2 %
Production taxes	$1.18	$0.94	$1.13	$0.24	$(0.19)	26 %	(17)%
Ad valorem tax expense	$0.34	$0.21	$0.39	$0.13	$(0.18)	62 %	(46)%
General and administrative	$2.71	$2.29	$2.46	$0.42	$(0.17)	18 %	(7)%
Depletion, depreciation, amortization, and	$12.53	$14.30	$14.34	$(1.77)	$(0.04)	(12)%	— %

asset retirement obligation liability accretion							
Derivative settlement gain (2)	$0.48	$5.96	$7.98	$(5.48)	$(2.02)	(92)%	(25)%
Earnings per share information							
Basic net loss per common share	$(1.44)	$(9.90)	$(6.61)	$8.46	$(3.29)	85 %	(50)%
Diluted net loss per common share	$(1.44)	$(9.90)	$(6.61)	$8.46	$(3.29)	85 %	(50)%
Basic weighted-average common shares outstanding (in thousands)	111,428	76,568	67,723	34,860	8,845	46 %	13 %
Diluted weighted-average common shares outstanding (in thousands)	111,428	76,568	67,723	34,860	8,845	46 %	13 %

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

(2) Gas derivative settlements for the year ended December 31, 2015 included $15.3 million of early settlements of futures contracts as a result of divesting assets in our Mid-Continent region. These early settlements increased the effect of derivative settlements by $0.24 per BOE for the year ended December 31, 2015.

We present per BOE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis. Average net daily production for the year ended December 31, 2017, decreased 19 percent compared with the same period in 2016. This decrease is primarily due to property divestitures across our regions in the last half of 2016 and the first quarter of 2017, specifically the sale of our Raven/Bear Den and outside-operated Eagle Ford shale assets. When excluding production from all assets sold in 2016 and 2017, daily production from retained assets and assets acquired increased approximately eight percent, which is driven primarily by our ramp up in the Midland Basin. Overall, we anticipate 2018 total production to remain flat compared with 2017, as we expect production increases in our Midland Basin program to be offset by the loss of production from our outside-operated Eagle Ford shale assets that we divested of in the first quarter of 2017 and lower activity levels in our operated Eagle Ford shale program. On a retained asset basis, we expect production to increase and the percentage of oil relative to our total product mix to also increase in 2018 compared with 2017. Please refer to Comparison of Financial Results and Trends Between 2017 and 2016 and Between 2016 and 2015 below for additional 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 effects of derivative settlements on a per BOE basis for the year ended December 31, 2017, increased 32 percent compared with the same period in 2016. Commodity prices were at multi-year lows in early 2016, began to recover in the second half of 2016, and fluctuated throughout 2017. Overall, commodity prices for all products were higher in 2017 compared with the prior year. Our derivative contracts resulted in a $0.48 settlement gain on a per BOE basis for the year ended December 31, 2017, which was a 92 percent decrease compared with 2016 settlements. Overall, there was a slight increase in our realized price after the effect of derivative settlements for the year ended December 31, 2017, when compared with the same period in 2016.

Lease operating expense ("LOE") on a per BOE basis for the year ended December 31, 2017, increased 26 percent compared with the same period in 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. We also experienced higher unanticipated LOE costs in our operated Eagle Ford shale program during the second half of 2017. For 2018, we expect LOE on a per BOE basis to be higher compared with 2017, as our product mix continues to shift toward more oil production, which typically has higher LOE per BOE. We expect to experience volatility in our LOE as a result of changes in industry activity and the effects this has on service provider costs, changes in total production, changes in our overall production mix, and timing of workover projects.

Transportation costs on a per BOE basis for the year ended December 31, 2017, decreased 11 percent compared with the same period in 2016. This decrease was primarily driven by the sale of our outside-operated Eagle Ford shale assets in the first quarter of 2017, which had higher average transportation costs. Going forward, we expect total transportation expense 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 2018 as production from our Midland Basin assets becomes a larger portion of our total production. The majority of our Midland Basin production is currently sold at the wellhead, and therefore, we incur minimal transportation expense on these assets.

Production taxes on a per BOE basis for the year ended December 31, 2017, increased 26 percent compared with the same period in 2016, due to a 32 percent increase in our realized price per BOE before the effect of derivative settlements, partially offset by a decrease in our production tax rate. Our production tax rate for the years ended December 31, 2017, and 2016 was 4.2 percent and 4.4 percent, respectively. The decrease in our production tax rate is primarily a result of divesting our Raven/Bear Den and other Rocky Mountain assets, which were taxed at higher rates than our Texas assets. We generally expect production tax expense to trend with oil, gas, and NGL production revenue on an absolute and per BOE basis. If prices in 2018 remain consistent with strip pricing as of February 14, 2018, as presented above within Oil, Gas, and NGL Prices, we would expect higher production tax expense in 2018 as compared with 2017 due to the expected increase in the percentage of oil in our overall production mix and higher realized prices. Product mix, the location of production, and incentives to encourage oil and gas development can all impact the amount of production tax we recognize.

Ad valorem tax expense on a per BOE basis for the year ended December 31, 2017, increased 62 percent compared with the same period in 2016, due to increased property tax valuations as a result of the increase in the overall value attributed to our reserve volumes during 2017. The majority of ad valorem tax expense is related to our Texas properties, which are the focus of our 2018 development plan. As a result, we expect an increase in ad valorem tax expense in 2018 as compared with 2017 on both an absolute and per BOE basis.

General and administrative ("G&A") expense increased 18 percent on a per BOE basis for the year ended December 31, 2017, compared with the same period in 2016, due primarily to the decrease in production volumes as a result of recent divestitures. We expect G&A expense on an absolute basis to increase in 2018 compared with 2017 due to an anticipated increase in headcount. We expect G&A expense on a per BOE basis in 2018 to slightly increase compared with 2017, as a result of increased G&A expense on an absolute basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense on a per BOE basis decreased 12 percent for the year ended December 31, 2017 compared with the same period in 2016, as a result of divested assets, specifically our higher cost Raven/Bear Den assets sold at the end of 2016, our outside-operated Eagle Ford shale assets that were held for sale prior to being sold in the first quarter of 2017, and our Divide County, North Dakota assets that were classified as held for sale during the first quarter and a portion of the second quarter in 2017. These assets were not depleted while classified as held for sale. Our DD&A rate fluctuates as a result of impairments, divestiture activity, changes in our production mix, and changes in our total proved reserve volumes. In general, we expect DD&A expense on a per BOE basis in 2018 to increase slightly compared with 2017 as a result of a higher percentage of our production coming from our Midland Basin assets, which has a higher depletion rate than our Eagle Ford shale and Divide County assets. Please refer to Comparison of Financial Results and Trends Between 2017 and 2016 and Between 2016 and 2015 for additional discussion.

Please refer to Earnings per Share in Note 1 – Summary of Significant Accounting Policies in Part II, Item 8 of this report for additional discussion on the types of shares included in our basic and diluted net loss per common share calculations. Our basic and diluted weighted-average share count increased in 2017 compared with 2016 primarily due to the public and private equity offerings of our common stock made in the last half of 2016. We recorded a net loss for the years ended December 31, 2017, 2016, and 2015. Consequently, all potentially dilutive shares were anti-dilutive and were excluded from the calculation of diluted net loss per common share.

Comparison of Financial Results and Trends Between 2017 and 2016 and Between 2016 and 2015

Oil, gas, and NGL production, production revenue, and production expense

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

	Average Net Daily Production Increase (Decrease)	Production Revenue Increase (Decrease)	Production Expense Increase (Decrease)
	(MBOE/d)	(in millions)	(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)

We experienced a 19 percent decrease in average net equivalent daily production in 2017 compared with 2016 primarily as a result of divestiture activity. The decrease in production was offset by a 32 percent increase in realized prices on a per BOE basis, resulting in an overall six percent increase in oil, gas, and NGL production revenue in 2017 compared with 2016. Production expense decreased 15 percent in 2017 compared with 2016, primarily due to the decrease in net equivalent production volumes, as discussed above. On a per BOE basis, production expense increased slightly in 2017 compared with 2016 primarily due to the sale of our non-operated Eagle Ford assets in the first quarter of 2017, which had lower average lifting costs per BOE than our retained assets.

The following table presents the regional changes in our oil, gas, and NGL production, production revenues, and production expense between the years ended December 31, 2016, and 2015:

	Average Net Daily Production Increase (Decrease)	Production Revenue Increase (Decrease)	Production Expense Decrease
	(MBOE/d)	(in millions)	(in millions)
Permian	2.9	$ 35.9	$ (0.6)
South Texas & Gulf Coast	(20.3)	(240.8)	(93.6)
Rocky Mountain	(2.9)	(90.7)	(19.6)
Mid-Continent [1]	(4.6)	(25.9)	(12.2)
Total	(24.9)	$ (321.5)	$ (126.0)

[1] We divested our Mid-Continent assets in the second quarter of 2015.

We experienced a 14 percent decrease in average net equivalent daily production volumes in 2016 from 2015 primarily due to a reduction in our drilling and completion activity and assets divested in both years. Additionally, our realized price on a per BOE basis decreased nine percent in 2016 from 2015. Both of these factors resulted in a 21 percent decrease in oil, gas, and NGL production revenue between the two periods. Total production expense for the year ended December 31, 2016, decreased $126.0 million, or 17 percent, from the same period in 2015 due to a 14 percent decrease in net equivalent production volumes, continued declines in service provider costs, and a decrease in production taxes due to lower commodity prices. While our aggregate production decreased in 2016 as compared with 2015, this decrease was partially offset by an increase in production in our Permian region due to increased development activity and acquisition activity within that region. On a per BOE basis, production expense decreased slightly in 2016 compared with 2015 primarily due to the decreases in service provider costs and production taxes as a result of low commodity prices and decreases in our production revenues.

Please refer to A Year-to-Year Overview of Selected Production and Financial Information, Including Trends above for additional discussion of trends on a per BOE basis for the years ended December 31, 2017, 2016, and 2015.

Net gain (loss) on divestiture activity

	For the Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Net gain (loss) on divestiture activity	$(131.0)	$37.1	$43.0

The net loss on divestiture activity recorded for the year ended December 31, 2017 was primarily the result of $526.5 million of total impairments taken on our previously held for sale assets in Divide County, North Dakota. These assets were subsequently reclassified back into held for use in the second quarter of 2017 upon our decision to retain the assets due to offers submitted in the sales process not reaching our expectations. These impairments were partially offset by a $396.8 million net gain on the sale of our outside-operated Eagle Ford shale assets during the first quarter of 2017.

The net gain on divestiture activity recorded for the year ended December 31, 2016, was primarily a result of the approximate $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.

The net gain on divestiture activity recorded for the year ended December 31, 2015, was due to the $108.4 million net gain recorded on the sale of our Mid-Continent assets in the second quarter, partially offset by losses on certain other non-core assets sold during 2015.

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,		
	2017	2016	2015
	(in millions)		
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$557.0	$790.7	$921.0

DD&A expense for the year ended December 31, 2017, decreased 30 percent compared with the same period in 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.

DD&A expense for the year ended December 31, 2016, decreased 14 percent compared with the same period in 2015 due to a decrease in production volumes and the impact of assets sold or classified as held for sale throughout 2016.

Exploration

	For the Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Geological and geophysical expenses	$4.0	$11.0	$7.5
Exploratory dry hole	2.4	—	36.6
Overhead and other expenses	49.8	54.6	76.5
Total	$56.2	$65.6	$120.6

Exploration expense for the year ended December 31, 2017, decreased 14 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. In 2018, we expect to continue our focus on testing and delineating our Midland Basin acreage, and as a result, expect increased exploration activity and related expenses compared with 2017. However, exploration expense may vary depending upon allocated overhead and exploratory dry hole expense.

Exploration expense for the year ended December 31, 2016, decreased 46 percent compared with 2015 primarily due to $36.6 million of exploratory dry holes being expensed in 2015 compared to none being recorded in 2016, as well as reduced overhead costs as a result of reduced exploration activity in 2016. These decreases were partially offset by expenses incurred for a seismic study performed on our Midland Basin acreage in the fourth quarter of 2016.

Impairment of proved properties and Abandonment and impairment of unproved properties

	For the Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Impairment of proved properties	$3.8	$354.6	$468.7
Abandonment and impairment of unproved properties	$12.3	$80.4	$78.6

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. 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, unsuccessful exploration activities, and changing economics associated with volatile commodity prices. Additionally, changes in drilling plans, downward engineering revisions, or unsuccessful exploration efforts may result in proved and unproved property impairments. Any amount of future impairment is difficult to predict, but based on updated commodity price assumptions as of

February 14, 2018, we do not expect any material impairments in the first quarter of 2018 due to commodity price impacts. Please refer to Critical Accounting Policies and Estimates below for additional discussion.

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.

Proved and unproved property impairments recorded in 2015 were due to continued commodity price declines, largely impacting our Powder River Basin program and certain legacy and non-core assets, as well as our decision to reduce capital invested in the development of our east Texas exploration program in light of the sustained, low commodity price environment.

Impairment of other property and equipment

	For the Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Impairment of other property and equipment	$—	$—	$49.4

We impaired our gas gathering system assets in our east Texas program during the year ended 2015, in conjunction with the impairment of the associated proved and unproved properties resulting from our decision not to allocate additional capital to the program in light of sustained low commodity prices. We did not record impairments of other property and equipment for the years ended December 31, 2017, or 2016.

General and administrative

	For the Years Ended December 31,		
	2017	2016	2015
	(in millions)		
General and administrative	$120.6	$126.4	$157.7

G&A expense for the year ended December 31, 2017, decreased five percent from 2016 primarily due to decreased compensation expense resulting from lower average headcount for the full year in 2017. 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 decreased 20 percent in 2016 from 2015 primarily due to lower headcount and overhead costs during 2016 resulting from the closure of our Tulsa, Oklahoma regional office in the third quarter of 2015, a company-wide workforce reduction that occurred in the third quarter of 2016, and the closure of our Billings, Montana regional office in the fourth quarter of 2016. For the years ended December 31, 2016 and 2015, $5.1 million and $9.3 million, respectively, of exit and disposal costs related to these events was included in G&A expense.

Net derivative (gain) loss

	For the Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Net derivative (gain) loss	$26.4	$250.6	$(408.8)

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 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.
We recognized a net derivative gain of $408.8 million for the year ended December 31, 2015. For contracts that settled during 2015, the fair value was a net asset of $402.7 million at December 31, 2014, and net cash settlements totaled $512.6 million, resulting in a $109.9 million gain. Additionally, we recorded a $298.9 million mark-to-market gain on remaining contracts as of December 31, 2015, resulting from a decrease 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,		
	2017	2016	2015
	(in millions)		
Interest expense	$(179.3)	$(158.7)	$(128.1)

The $20.6 million, or 13 percent, increase in interest expense for the year ended December 31, 2017, compared with the same period in 2016, was primarily driven by an increase in total debt outstanding for the full year 2017 due to additional debt issuances in the second half of 2016, as presented in Note 5 – Long-Term Debt in Part II, Item 8 of this report.
The $30.6 million, or 24 percent, increase in interest expense for the year ended December 31, 2016, compared with the same period in 2015, was due to the additional debt issuances in 2016, as presented in Note 5 – Long-Term Debt in Part II, Item 8 of this report, as well as $10.0 million paid to terminate a second lien credit facility that was not necessary to fund a portion of one of our Midland Basin acquisitions.
Please refer to Overview of Liquidity and Capital Resources below for additional discussion of weighted-average interest and borrowing rates for the years presented.
Gain (loss) on extinguishment of debt

	For the Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Gain (loss) on extinguishment of debt	$—	$15.7	$(16.6)

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 (as defined and discussed in Note 5 – Long-Term Debt in Part II, Item 8 of this report), which includes approximately $16.4 million associated with the discount realized upon repurchase, slightly offset by approximately $700,000 related to the acceleration of unamortized deferred financing costs.
For the year ended December 31, 2015, we recorded a $16.6 million loss on the early extinguishment of our 6.625% Senior Notes due 2019 ("2019 Notes"), which included approximately $12.5 million associated with the premium paid for the tender offer and redemption of the notes and approximately $4.1 million for the acceleration of unamortized deferred financing costs.

Income tax benefit

	For the Years Ended December 31,		
	2017	2016	2015
	(in millions, except tax rate)		
Income tax benefit	$183.0	$444.2	$275.2
Effective tax rate	53.2 %	37.0 %	38.1 %

The increase in the effective tax rate in 2017 compared with 2016 is primarily due to enactment into law on December 22, 2017 of H.R.1, formally the Tax Cuts and Jobs Act (the "2017 Tax Act"). This law decreased the highest marginal corporate tax rate from 35 percent to 21 percent and resulted in an 18.5 percentage point nonrecurring adjustment affecting our effective tax rate, recorded in the fourth quarter of 2017. This increase was partially offset by a discrete expense recorded in the third quarter of 2017 relating to an excess tax deficiency from the settlement of employee share-based payment awards. The tax benefit also reflects 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. We are still planning to implement strategies to utilize deferred tax assets. In accordance with the 2017 Tax Act, our effective tax rate is expected to decrease significantly in 2018 and future years.

The decrease in the effective tax rate in 2016 compared with 2015 reflected the tax benefit of Oklahoma permanent tax benefits and claimed research and development credits recognized in 2015. The effective tax benefit rate realized in 2016 primarily includes a positive effect from the divestiture of properties in high marginal rate states and acquisition of properties in a lower marginal rate state, as well as a positive effect from the release of certain valuation allowances on utilized tax assets. The tax gain recognized on the Raven/Bear Den divestiture, which closed in the fourth quarter of 2016, is much larger than the estimated and recorded book gain. As a result, we were able to consider tax planning strategies which would allow for the utilization of net operating loss carryovers in certain states which we previously determined would expire before they could be used, as well as utilization of certain carryover federal tax deductions, limited based upon taxable income, which were also expected to expire.

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 in periods of prolonged weak commodity prices or to respond should commodity prices recover further.

Sources of Cash

We currently expect our 2018 capital program to be funded by cash flows from operations and proceeds from the divestiture of properties. As of December 31, 2017, our cash balance totaled $313.9 million, which combined with our $924.8 million of available borrowing capacity under our Credit Agreement, resulted in $1.2 billion in liquidity. In addition, as a result of our previously announced PRB Divestiture, which is expected to close in the first quarter of 2018, we expect to have additional cash from the sale of these assets of $500.0 million, subject to customary closing price adjustments. There can be no assurance that the PRB Divestiture will close on time or at all.

Although we anticipate cash flows from operations and divestiture proceeds will be sufficient to fund our expected 2018 capital program, we may also elect to borrow under our Credit Agreement, raise funds through debt or equity financings, or raise funds 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. See Credit Agreement below for discussion of the reduction in our borrowing base in early 2017. Our borrowing base could be further reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt. 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

Our Credit Agreement provides for a maximum loan amount of $2.5 billion and has a maturity date of December 10, 2019. On March 31, 2017, we entered into a Ninth Amendment to the Credit Agreement (the “Ninth Amendment”). Pursuant to the Ninth Amendment, and as part of the regular, semi-annual borrowing base redetermination process, the borrowing base and aggregate lender commitments under our Credit Agreement were reduced to $925 million. This expected decrease was primarily due to the sale of our outside-operated Eagle Ford shale assets in the first quarter of 2017 and the decrease in the value of our estimated proved reserves as of December 31, 2016. Additionally, as part of the Ninth Amendment, we are now able to enter into derivative contracts for an increased percentage of projected production volumes. The borrowing base redetermination process considers the value of both our (a) proved oil and gas properties reflected in our most recent reserve report, and (b) commodity derivative contracts, each as determined by our lender group. We expect an increase to our borrowing base and aggregate lender commitments during the next semi-annual redetermination scheduled for April 1, 2018, as a result of the increase in our estimated proved reserves at December 31, 2017. We had no outstanding balance under our Credit Agreement as of December 31, 2017, or 2016. 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 14, 2018, December 31, 2017, and December 31, 2016.

We must comply with certain financial and non-financial covenants under the Credit Agreement, including covenants limiting dividend payments and requiring us to maintain certain financial ratios, as defined by the Credit Agreement. Certain financial covenants under the Credit Agreement require, as of the last day of each fiscal quarter, our (a) ratio of senior secured debt to 12-month trailing adjusted EBITDAX to be not more than 2.75 to 1.0; (b) adjusted current ratio to be not less than 1.0 to 1.0; and (c) ratio of 12-month trailing adjusted EBITDAX to interest expense to be not less than 2.0 to 1.0. We were in compliance with all financial and non-financial covenants under the Credit Agreement as of December 31, 2017, 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 loss and net cash provided by operating activities to adjusted EBITDAX.

We had minimal credit facility activity during 2017, due to our significant cash balance resulting from the divestiture of our Raven/Bear Den assets in December 2016 and proceeds received from the sale of our outside-operated Eagle Ford shale assets during the first quarter of 2017. Our daily weighted-average credit facility debt balance was approximately $13.1 million, $183.8 million, and $253.7 million for the years ended December 31, 2017, 2016, and 2015, respectively. Cash flows provided by our operating activities, divestiture proceeds, capital markets activity, 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, 2017, 2016, and 2015.

	For the Years Ended December 31,		
	2017	2016	2015
Weighted-average interest rate	6.4%	6.2%	6.0%
Weighted-average borrowing rate	5.8%	5.7%	5.5%

Our weighted-average interest rates and weighted average borrowing rates for the years ended December 31, 2017, 2016, and 2015, have been impacted by the timing of Senior Notes and Senior Convertible Notes 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. The increase in our weighted-average interest rate and weighted-average borrowing rate for the year ended December 31, 2017, as compared with 2016 and 2015, is largely due to the issuance of the Senior Convertible Notes and the 2026 Notes in the third quarter of 2016. Further impacting these rates is the timing and amount of Senior Notes redemptions, changes in our aggregate lender commitment amount under our Credit Agreement, and the average balance on our credit facility under the Credit Agreement. 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 and the premium paid in 2015 for the tender offer and redemption of the 2019 Notes. 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 2017, we spent $978.2 million on capital expenditures and on acquiring proved and 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 acquisition opportunities, our cash flows from operating, investing, and financing activities, and our ability to assimilate acquisitions and 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. During 2017, we repurchased a portion of our Senior Notes in open market transactions at a slight premium, as discussed in more detail in Note 5 – Long-Term Debt in Part II, Item 8 of this report. As part of our strategy for 2018, we will 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 2017, 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 2018.

During 2017, we paid $11.1 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 2017 and 2016 and Between 2016 and 2015

The following tables present changes in cash flows between the years ended December 31, 2017, 2016, and 2015, for our operating, investing, and financing activities. Certain prior period 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 of Part II, Item 8 for additional discussion of the change in presentation on the accompanying consolidated statements of cash flows ("accompanying statements of cash flows") as a result of adopting new accounting standards. The analysis following each table should be read in conjunction with our 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	
	2017	2016	2015 (as adjusted)	2017/2016	2016/2015	2017/2016	2016/2015
Net cash provided by operating activities (in millions)	$515.4	$552.8	$ 990.8	$(37.4)	$(438.0)	(7)%	(44)%

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 decline 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 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 the same period in 2016, as a result of a 20 percent decline 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 the same period in 2016, primarily as a result of the decrease in average headcount for 2017. Further, net cash provided by operating activities is affected by working capital changes and the timing of cash receipts and disbursements. During 2016, we paid $10.0 million to terminate a second lien facility that was not needed to fund the Rock Oil Acquisition.

Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, including derivative cash settlements, decreased $588.0 million, or 35 percent, to $1.1 billion for the year ended December 31, 2016, compared with the same period in 2015. This decrease was primarily a result of the decline in production volumes, realized commodity prices, and derivative cash settlements. Cash paid for LOE in 2016 decreased $52.6 million, or 21 percent, to $199.9 million compared with the same period in 2015, due primarily to a 14 percent decrease in production volumes and a reduction in service provider costs. During 2016, we paid $10.0 million to terminate a second lien facility that was not needed to fund the Rock Oil Acquisition. The remaining change was related to decreases in cash G&A expense, exploration overhead, and ad valorem taxes, as well as changes in working capital balances.

In 2017, we adjusted certain prior period amounts to conform to the current period presentation on the consolidated financial statements. As a result, we reclassified $12.5 million associated with the premium for the tender offer and redemption of the 2019 Notes from operating activities to financing activities, resulting in an increase in net cash provided by operating activities in 2015. 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 on the accompanying statements of cash flows as a result of adopting new accounting standards.

Investing Activities

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2017	2016 (as adjusted)	2015	2017/2016	2016/2015	2017/2016	2016/2015
Net cash used in investing activities (in millions)	$(201.5)	$(1,867.6)	$(1,144.6)	$1,666.1	$(723.0)	(89)%	63 %

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 assets 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.

Net cash used in investing activities increased for the year ended December 31, 2016, compared with the same period in 2015. During 2016, cash paid to acquire proved and unproved properties in the Midland Basin totaled $2.2 billion, whereas we had no significant acquisition activity in 2015. Net proceeds from the sale of oil and gas properties increased $588.1 million for the year ended December 31, 2016, compared with the same period in 2015, due to proceeds from the divestitures of our Raven/Bear Den and other none-core Permian and Rocky Mountain assets in 2016 exceeding proceeds from the sale of our Mid-Continent assets in 2015. Capital expenditures in 2016 decreased $863.7 million, or 58 percent, compared with 2015 as a result of reduced drilling and completion activities and lower service provider costs, as well as a significant amount of accrued 2014 drilling and completion payables paid in early 2015.

In 2017, we adjusted certain prior period 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 the change in presentation on the accompanying statements of cash flows as a result of adopting new accounting standards.

Financing Activities

	For the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2017	2016	2015 (as adjusted)	2017/2016	2016/2015	2017/2016	2016/2015
Net cash provided by (used in) financing activities (in millions)	$(12.3)	$1,327.2	$ 153.7	$(1,339.5)	$ 1,173.5	(101)%	764 %

We had a zero balance on our credit facility as of December 31, 2017 and 2016, due to our cash balance resulting from the proceeds received from the sale of our Raven/Bear Den assets in December 2016 and proceeds received from the sale of our outside-operated Eagle Ford shale assets during 2017. Consequently, net credit facility repayments were zero in 2017. This compares to net repayments of $202.0 million during the year ended December 31, 2016. During 2016, we received $934.1 million of net proceeds from two public equity offerings, $491.6 million of net proceeds from our 2026 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 pay down our credit facility balance. 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. During 2015, we received $491.0 million of net proceeds from the issuance of our 2025 Notes, which were used for the tender and redemption of the $350.0 million principal amount of our 2019 Notes. Please refer to Note 5 – Long-Term Debt and Note 13 – Equity in Part II, Item 8 of this report for additional discussion.

In 2017, we adjusted certain prior period amounts to conform to the current period presentation on the consolidated financial statements. As a result, we reclassified $12.5 million associated with the premium for the tender offer and redemption of the 2019 Notes from operating activities to financing activities, resulting in a decrease in net cash provided by financing activities in 2015. 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 on the accompanying statements of cash flows as a result of adopting new accounting standards.

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, 2017, and through the filing of this report, 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, 2017, our outstanding fixed-rate debt totaled $3.0 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 2017 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 $65.4 million, $36.9 million, and $23.0 million, respectively. If commodity prices had been 10 percent lower, our derivative settlements would have been higher, partially offsetting the decrease in production revenues quantified above.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. The fair value of our commodity derivative contracts are largely determined by estimates of the forward curves of the relevant price indices. At December 31, 2017, 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 $99.2 million, $24.6 million, and $31.7 million, respectively.

Schedule of Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2017, 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)	$2,973.9	$—	$—	$1,078.9	$1,895.0
Interest payments (2)	1,050.8	174.7	346.5	310.5	219.1
Delivery commitments (3)	463.4	59.6	197.4	155.5	50.9
Operating leases and contracts (3)	111.3	54.2	26.6	19.2	11.3
Asset retirement obligations (4)	139.1	6.3	28.4	5.9	98.5
Derivative liabilities (5)	245.6	173.3	72.3	—	—
Other (6)	41.4	4.0	16.3	21.1	—
Total	$5,025.5	$472.1	$687.5	$1,591.1	$2,274.8

(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 payments may vary significantly. As of December 31, 2017, 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, 2017, the above table reflects 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.

(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, 2017. 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, 2017, are shown as an obligation in 1-3 years due to the substantial uncertainty on the timing of plugging or re-entering these wells. Please refer to Note 9 – 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, 2017, 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 $41.0 million, for which we have estimated the timing of future payments based on historical annual contribution amounts.

Off-Balance Sheet Arrangements

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

We evaluate our transactions to determine if any variable interest entities exist. If it is determined 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 in 2017 or 2016.

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. 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, 2017, 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, 2017. 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, reducing future earnings. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for or produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of proved and unproved properties for impairment. Changes in depletion or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period the reserve estimates change.

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,		
	2017	2016	2015
	MMBOE Change	MMBOE Change	MMBOE Change
Revisions resulting from performance	7.4	(18.1)	47.3
Removal of proved undeveloped reserves no longer in our five-year development plan	(13.9)	(43.0)	(79.4)
Revisions resulting from price changes	23.1	(35.1)	(116.5)
Total	16.6	(96.2)	(148.6)

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

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

	For the year ended December 31, 2017	
	MMBOE Change	Percentage Change
10 percent decrease in SEC pricing [1]	(17.3)	(4)%
Average NYMEX strip pricing as of fiscal year end [2]	NM	NM
10 percent decrease in proved undeveloped reserves [3]	(25.3)	(5)%

(1) The change solely reflects the impact of a 10 percent decrease in SEC pricing to the total reported estimated proved reserve volumes as of December 31, 2017, 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 impact of replacing SEC pricing with average NYMEX strip pricing as of December 31, 2017, did not result in a meaningful change to our total reported proved reserve volumes as SEC pricing of $51.34 per Bbl for oil, $3.00 per MMBtu for gas, and $27.69 per Bbl for NGLs as of December 31, 2017, was not materially different than five year average NYMEX strip pricing of $54.71 per Bbl for oil, $2.84 per MMBtu for gas, and $29.22 per Bbl for NGLs as of December 31, 2017.

(3) The change solely reflects a 10 percent decrease in proved undeveloped reserves as of December 31, 2017, 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 updated commodity price assumptions as of February 14, 2018, we do not expect any material impairments in the first quarter of 2018 due to 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 impairments of oil and gas properties and other property and equipment recorded for the years ended December 31, 2017, 2016, and 2015.

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 9 – Asset Retirement Obligations in Part II, Item 8 of this report for additional discussion.

Revenue Recognition. 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. We derive our revenue primarily from the sale of produced oil, gas, and NGLs. Revenue is recognized when our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. 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, their 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 year end revenue accrual would have impacted total operating revenues by approximately $9.7 million in 2017.

Effective January 1, 2018, our revenue recognition policy changed due to the adoption of new accounting guidance. Please refer to Note 1 – Summary of Significant Accounting Policies under the heading Recently Issued Accounting Standards 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. 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 benefit by approximately $3.4 million for the year ended December 31, 2017.

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 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 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, 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 for 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 June 2017, the EPA proposed a 2-year stay of the compliance requirements in the 2016 NSPS. 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 are intended to reduce the waste of gas from flaring, venting, and leaks by oil and gas production. The rule includes 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 increases royalty payments for "waste" gas that is released in contravention of the rule requirements. A preliminary injunction sought by industry groups was denied in U.S. District Court and the regulation went into effect on January 17, 2017; however, on December 8, 2017, the BLM finalized a rule suspending or delaying many of the provisions of the regulation while it reviews the regulation. This suspension of the rule is being challenged in the courts.

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 and issued an advanced notice of proposed rulemaking asking for comments on a replacement rule.

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 may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods, and other climatic events. If any such effects were to occur, they 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 46 and 44 percent of our production on a BOE basis in 2017 and 2016, 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 one-time 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 Credit Agreement 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 senior secured debt to adjusted EBITDAX and a minimum permitted ratio of adjusted EBITDAX to interest, 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 loss and net cash provided by operating activities to adjusted EBITDAX for the periods presented:

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Net loss (GAAP)	$(160,843)	$(757,744)	$(447,710)
Interest expense	179,257	158,685	128,149
Interest income [(1)]	(3,968)	(362)	(649)
Income tax benefit	(182,970)	(444,172)	(275,151)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	557,036	790,745	921,009
Exploration [(2)]	49,879	59,194	113,158
Impairment of proved properties	3,806	354,614	468,679
Abandonment and impairment of unproved properties	12,272	80,367	78,643
Impairment of other property and equipment	—	—	49,369
Stock-based compensation expense	22,700	26,897	27,467
Net derivative (gain) loss	26,414	250,633	(408,831)
Derivative settlement gain [(3)]	21,234	329,478	512,566
Net (gain) loss on divestiture activity	131,028	(37,074)	(43,031)
(Gain) loss on extinguishment of debt	35	(15,722)	16,578
Other, net	8,820	(4,764)	(15,471)
Adjusted EBITDAX (Non-GAAP)	664,700	790,775	1,124,775
Interest expense	(179,257)	(158,685)	(128,149)
Interest income [(1)]	3,968	362	649
Income tax benefit	182,970	444,172	275,151
Exploration [(2)]	(49,879)	(59,194)	(113,158)
Exploratory dry hole expense	2,381	(16)	36,612
Amortization of debt discount and deferred financing costs	16,276	9,938	7,710
Deferred income taxes	(192,066)	(448,643)	(276,722)
Plugging and abandonment	(2,735)	(6,214)	(7,496)
Other, net	(581)	1,063	9,707
Changes in current assets and liabilities	69,613	(20,754)	61,728
Net cash provided by operating activities (GAAP) [(4)]	$515,390	$552,804	$990,807

(1) Interest income is included in "Other, net" on the accompanying statements of operations in Part II, Item 8 of this report.

(2) Stock-based compensation expense is a component of exploration expense and general and administrative expense 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) Derivative settlement gain for the year ended December 31, 2015, includes $15.3 million of gains on the early settlement of futures contracts as a result of divesting our Mid-Continent assets.

(4) Net cash provided by operating activities (GAAP) for the year ended December 31, 2015 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 of Part II, Item 8 of this report for additional discussion of the change in presentation on the accompanying statements of cash flows as a result of a new accounting standard.

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, 2017 and 2016, the related consolidated statements of operations, comprehensive income (loss), stockholders' equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "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, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with 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, 2017, 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, 2018 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, 2018

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

	December 31, 2017	2016
ASSETS		
Current assets:		
Cash and cash equivalents	$313,943	$9,372
Accounts receivable	160,154	151,950
Derivative assets	64,266	54,521
Prepaid expenses and other	10,752	8,799
Total current assets	549,115	224,642
Property and equipment (successful efforts method):		
Proved oil and gas properties	6,139,379	5,700,418
Less - accumulated depletion, depreciation, and amortization	(3,171,575)	(2,836,532)
Unproved oil and gas properties	2,047,203	2,471,947
Wells in progress	321,347	235,147
Oil and gas properties held for sale, net	111,700	372,621
Other property and equipment, net of accumulated depreciation of $49,985 and $42,882, respectively	106,738	137,753
Total property and equipment, net	5,554,792	6,081,354
Noncurrent assets:		
Derivative assets	40,362	67,575
Other noncurrent assets	32,507	19,940
Total other noncurrent assets	72,869	87,515
Total assets	$6,176,776	$6,393,511
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$386,630	$299,708
Derivative liabilities	172,582	115,464
Total current liabilities	559,212	415,172
Noncurrent liabilities:		
Revolving credit facility	—	—
Senior Notes, net of unamortized deferred financing costs	2,769,663	2,766,719
Senior Convertible Notes, net of unamortized discount and deferred financing costs	139,107	130,856
Asset retirement obligations	103,026	96,134
Asset retirement obligations associated with oil and gas properties held for sale	11,369	26,241
Deferred income taxes	79,989	315,672
Derivative liabilities	71,402	98,340
Other noncurrent liabilities	48,400	47,244
Total noncurrent liabilities	3,222,956	3,481,206
Commitments and contingencies (note 6)		
Stockholders’ equity:		
	1,117	1,113

Common stock, $0.01 par value - authorized: 200,000,000 shares; issued and outstanding: 111,687,016 and 111,257,500 shares, respectively		
Additional paid-in capital	1,741,623	1,716,556
Retained earnings	665,657	794,020
Accumulated other comprehensive loss	(13,789)	(14,556)
Total stockholders’ equity	2,394,608	2,497,133
Total liabilities and stockholders’ equity	$6,176,776	$6,393,511

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,		
	2017	2016	2015
Operating revenues and other income:			
Oil, gas, and NGL production revenue	$1,253,783	$1,178,426	$1,499,905
Net gain (loss) on divestiture activity	(131,028)	37,074	43,031
Other operating revenues	6,621	1,950	14,029
Total operating revenues and other income	1,129,376	1,217,450	1,556,965
Operating expenses:			
Oil, gas, and NGL production expense	507,906	597,565	723,633
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	557,036	790,745	921,009
Exploration	56,179	65,641	120,569
Impairment of proved properties	3,806	354,614	468,679
Abandonment and impairment of unproved properties	12,272	80,367	78,643
Impairment of other property and equipment	—	—	49,369
General and administrative	120,585	126,428	157,668
Net derivative (gain) loss	26,414	250,633	(408,831)
Other operating expenses	13,667	10,772	25,009
Total operating expenses	1,297,865	2,276,765	2,135,748
Loss from operations	(168,489)	(1,059,315)	(578,783)
Non-operating income (expense):			
Interest expense	(179,257)	(158,685)	(128,149)
Gain (loss) on extinguishment of debt	(35)	15,722	(16,578)
Other, net	3,968	362	649
Loss before income taxes	(343,813)	(1,201,916)	(722,861)
Income tax benefit	182,970	444,172	275,151
Net loss	$(160,843)	$(757,744)	$(447,710)
Basic weighted-average common shares outstanding	111,428	76,568	67,723
Diluted weighted-average common shares outstanding	111,428	76,568	67,723
Basic net loss per common share	$(1.44)	$(9.90)	$(6.61)
Diluted net loss per common share	$(1.44)	$(9.90)	$(6.61)

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,		
	2017	2016	2015
Net loss	$(160,843)	$(757,744)	$(447,710)
Other comprehensive income (loss), net of tax:			
Pension liability adjustment [1]	767	(1,154)	(2,090)
Total other comprehensive income (loss), net of tax	767	(1,154)	(2,090)
Total comprehensive loss	$(160,076)	$(758,898)	$(449,800)

[1] Please refer to Note 8 – Pension Benefits for additional discussion on the pension liability adjustment.

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

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

	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
	Shares	Amount				
Balances, January 1, 2015	67,463,060	$ 675	$ 283,295	$ 2,013,997	$ (11,312)	$ 2,286,655
Net loss	—	—	—	(447,710)	—	(447,710)
Other comprehensive loss	—	—	—	—	(2,090)	(2,090)
Cash dividends, $ 0.10 per share	—	—	—	(6,772)	—	(6,772)
Issuance of common stock under Employee Stock Purchase Plan	197,214	2	4,842	—	—	4,844
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	375,523	4	(8,682)	—	—	(8,678)
Stock-based compensation expense	39,903	—	27,467	—	—	27,467
Other	—	—	(1,315)	—	—	(1,315)
Balances, December 31, 2015	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

(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.

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

	For the Years Ended December 31,		
	2017	2016 (as adjusted)	2015 (as adjusted)
Cash flows from operating activities:			
Net loss	$(160,843)	$(757,744)	$(447,710)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Net (gain) loss on divestiture activity	131,028	(37,074)	(43,031)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	557,036	790,745	921,009
Exploratory dry hole expense	2,381	(16)	36,612
Impairment of proved properties	3,806	354,614	468,679
Abandonment and impairment of unproved properties	12,272	80,367	78,643
Impairment of other property and equipment	—	—	49,369
Stock-based compensation expense	22,700	26,897	27,467
Net derivative (gain) loss	26,414	250,633	(408,831)
Derivative settlement gain	21,234	329,478	512,566
Amortization of debt discount and deferred financing costs	16,276	9,938	7,710
(Gain) loss on extinguishment of debt	35	(15,722)	16,578
Deferred income taxes	(192,066)	(448,643)	(276,722)
Plugging and abandonment	(2,735)	(6,214)	(7,496)
Other, net	8,239	(3,701)	(5,764)
Changes in current assets and liabilities:			
Accounts receivable	13,997	(10,562)	140,200
Prepaid expenses and other	(1,953)	8,478	2,563
Accounts payable and accrued expenses	44,985	(53,210)	(86,267)
Accrued derivative settlements	12,584	34,540	5,232
Net cash provided by operating activities	515,390	552,804	990,807
Cash flows from investing activities:			
Net proceeds from the sale of oil and gas properties	776,719	946,062	357,938
Capital expenditures	(888,353)	(629,911)	(1,493,608)
Acquisition of proved and unproved oil and gas properties	(89,896)	(2,183,790)	(7,984)
Other, net	—	—	(985)
Net cash used in investing activities	(201,530)	(1,867,639)	(1,144,639)
Cash flows from financing activities:			
Proceeds from credit facility	406,000	947,000	1,872,500
Repayment of credit facility	(406,000)	(1,149,000)	(1,836,500)
Debt issuance costs related to credit facility	—	(3,132)	—
Net proceeds from Senior Notes	—	491,640	490,951
Cash paid to repurchase Senior Notes	(2,344)	(29,904)	(350,000)
Cash paid for extinguishment of debt	(13)	—	(12,455)
Net proceeds from Senior Convertible Notes	—	166,617	—
Cash paid for capped call transactions	—	(24,195)	—
Net proceeds from sale of common stock	2,623	938,268	4,844

Dividends paid	(11,144)	(7,751)	(6,772)
Net share settlement from issuance of stock awards	(1,240)	(2,354)	(8,678)
Other, net	(171)	—	(160)
Net cash provided by (used in) financing activities	(12,289)	1,327,189	153,730
Net change in cash, cash equivalents, and restricted cash [1]	301,571	12,354	(102)
Cash, cash equivalents, and restricted cash at beginning of period [1]	12,372	18	120
Cash, cash equivalents, and restricted cash at end of period [1]	$313,943	$12,372	$18

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 (Continued)
(in thousands)

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

	For the Years Ended December 31,		
	2017	2016 (as adjusted)	2015 (as adjusted)
Supplemental cash flows information:			
Operating activities:			
Cash paid for interest, net of capitalized interest	$(164,097)	$(129,761)	$(126,988)
Net cash (refunded) paid for income taxes	$5,986	$(4,690)	$1,630
Investing activities:			
Changes in capital expenditure accruals and other	$7,309	$8,044	$(210,819)
Supplemental non-cash investing activities:			
Carrying value of properties exchanged	$293,963	$733	$—
Supplemental non-cash financing activities:			
Issuance of common stock for an asset acquisition [2]	$—	$437,194	$—
Non-cash (gain) loss on extinguishment of debt, net	$22	$(15,722)	$4,123

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(1) Refer to Note 1 – Summary of Significant Accounting Policies for a reconciliation of cash, cash equivalents, and restricted cash reported to the amounts reported within the accompanying balance sheets.

(2) 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 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 its wholly-owned subsidiaries 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 subsequent events after the balance sheet date of December 31, 2017, 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 consist mainly of receivables from oil, gas, and NGL purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically 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 two months and the Company has had minimal bad debts.

Although diversified among many companies, collectability 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 2 – 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,		
	2017	2016	2015
Major customer #1 (1)	10%	5 %	4 %
Major customer #2 (2)	7 %	18%	21%
Group #1 of entities under common ownership (3)	17%	15%	10%
Group #2 of entities under common ownership (3)	8 %	8 %	11%

(1) This major customer is a purchaser of the Company's production from its Permian region.

(2) This major customer was the operator of the Company's outside-operated Eagle Ford shale program, which was divested of during the first quarter of 2017. Prior to the divestiture, the Company was party to various marketing agreements, which included certain gathering, transportation, and processing throughput commitments. Because the Company shared with the operator the risk of non-performance by its counterparty purchasers, the Company included the operator as a major customer in the table above. Several of the operator's counterparty purchasers under these contracts were also direct purchasers of the Company's production from other areas.

(3) In the aggregate these groups of entities under common ownership represent more than 10 percent of total oil, gas, and NGL production revenue for the period(s) shown, however, none of the individual entities 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 costs, including lease and well equipment and intangible development costs, are depleted as a group of assets (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 the carrying costs may not be recoverable. Expected future discounted cash flows are calculated on all estimated proved reserves and risk-adjusted probable and possible reserves using discount rates and price forecasts that management believes are representative of current market conditions. 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, adjusted for basis differentials, 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. Please refer to Note 11 – Fair Value Measurements for additional discussion.

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. When successful wells are drilled on unproved leases, unproved property costs allocated to those leases are reclassified to proved properties and depleted on a units-of-production basis. An impairment is recorded on unproved property when the Company determines that either the property will not be developed or the carrying value is not realizable. Please refer to Note 11 – Fair Value Measurements for additional discussion.

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 G&G, 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 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 where appropriate. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

A long-lived asset is evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. The Company uses an income valuation technique if there is not a market-observable price for the asset. Please refer to Note 11 – Fair Value Measurements for additional discussion.

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. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions and Note 11 – Fair Value Measurements for additional discussion.

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 and 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 changes in inflation factors or the Company's credit-adjusted risk-free rate as market conditions warrant. Please refer to Note 9 – Asset Retirement Obligations for a reconciliation of the Company's total asset retirement obligation liability as of December 31, 2017, and 2016.

Derivative Financial Instruments

The Company seeks to manage or reduce commodity price risk on its production by entering into derivative contracts. The Company seeks to minimize its basis risk and indexes its oil derivative contracts to NYMEX prices, its NGL derivative contracts to OPIS prices, and its gas derivative contracts to various regional index prices associated with pipelines into which the Company's gas production is sold. 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. 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 when the Company's production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to the purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses knowledge of its properties and historical performance, contractual agreements, NYMEX, OPIS, and local spot market prices, quality and transportation differentials, and other factors as the basis for these estimates. The Company follows the sales method of accounting for gas production imbalances. If the Company's sales volumes for a well exceed the Company's proportionate share of production from the well, a liability is recognized to the extent that the Company's share of estimated remaining recoverable reserves from the well is insufficient to satisfy this imbalance. Effective January 1, 2018, the Company's revenue recognition policy changed due to the adoption of new accounting guidance. Please refer to Recently Issued Accounting Standards below for additional discussion.

Stock-Based Compensation

At December 31, 2017, the Company had stock-based employee compensation plans that included RSUs and 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 included within general and administrative expense and exploration expense in the accompanying statements of operations. 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

Basic net income (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 (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 year ended December 31, 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 (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, 2016, and 2015, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted net loss per common share.

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

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Anti-dilutive	264	280	256

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

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands, except per share data)		
Net loss	$(160,843)	$(757,744)	$(447,710)
Basic weighted-average common shares outstanding	111,428	76,568	67,723
Add: dilutive effect of non-vested RSUs and contingent PSUs	—	—	—
Add: dilutive effect of Senior Convertible Notes	—	—	—
Diluted weighted-average common shares outstanding	111,428	76,568	67,723
Basic net loss per common share	$(1.44)	$(9.90)	$(6.61)
Diluted net loss per common share	$(1.44)	$(9.90)	$(6.61)

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, 2017, and 2016. 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 in onshore 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 2017 or 2016.

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. Going forward, excess tax benefits will be presented in operating activities on the accompanying statements of cash flows.
- Also 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 $0.4 million, and a net $0.7 million 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 has reclassified 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 statements of cash flows. The December 31, 2016, and 2015 accompanying statements of cash flows line items that were adjusted as a result of the adoption of ASU 2016-15 and ASU 2016-18 are summarized as follows:

	For the Years Ended December 31,			
	2016		2015	
	As Reported	As Adjusted	As Reported	As Adjusted
	(in thousands)			
Non-cash (gain) loss on extinguishment of debt	$(15,722)	N/A	$4,123	N/A
(Gain) loss on extinguishment of debt	N/A	$(15,722)	N/A	$16,578
Net cash provided by operating activities	$552,804	$552,804	$978,352	$990,807
Other, net	$(3,000)	$—	$(985)	$(985)
Net cash used in investing activities	$(1,870,639)	$(1,867,639)	$(1,144,639)	$(1,144,639)
Cash paid for extinguishment of debt	N/A	$—	N/A	$(12,455)
Net cash provided by financing activities	$1,327,189	$1,327,189	$166,185	$153,730
Net change in cash and cash equivalents	$9,354	N/A	$(102)	N/A
Net change in cash, cash equivalents, and restricted cash	N/A	$12,354	N/A	$(102)
Cash and cash equivalents at beginning of period	$18	N/A	$120	N/A
Cash, cash equivalents, and restricted cash at beginning of period	N/A	$18	N/A	$120
Cash and cash equivalents at end of period	$9,372	N/A	$18	N/A
Cash, cash equivalents, and restricted cash at end of period	N/A	$12,372	N/A	$18

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the accompanying balance sheets to the amounts shown in the accompanying statements of cash flows:

	December 31,		
	2017	2016	2015
	(in thousands)		
Cash and cash equivalents	$313,943	$9,372	$ 18
Restricted cash [1]	—	3,000	—
Total cash, cash equivalents, and restricted cash shown in the accompanying statements of cash flows	$313,943	$12,372	$ 18

(1) Restricted cash is included in other noncurrent assets on the accompanying balance sheets.

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. The Company adopted ASU 2014-09 and all related ASUs using a modified retrospective transition method on the effective date of January 1, 2018 and will apply the new guidance to contracts for which all, or substantially all, of the revenue has not been recognized as of December 31, 2017 under legacy revenue guidance. This adoption will not result in a material change to current or prior period results, business processes, systems, or controls. However, upon adoption the Company will expand its current disclosures to comply with the disclosure requirements of the new guidance.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which requires lessees to recognize a right-of-use asset and a lease liability for virtually all leases currently classified as operating leases. The Company is currently analyzing the impact this standard will have on the Company's contract portfolio, including non-cancelable leases, drilling rigs, pipeline gathering, transportation, gas processing, and other existing arrangements. Further, the Company is evaluating current accounting policies, applicable systems, controls, and processes to support the potential recognition and disclosure changes resulting from ASU 2016-02. Based upon the Company's initial assessment, ASU 2016-02 is expected to result in an increase in assets and liabilities recorded. The Company will adopt ASU 2016-02 using a modified retrospective method on the effective date of January 1, 2019. In January 2018, the FASB issued ASU No. 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842 ("ASU 2018-01"). ASU 2018-01 provides an optional transitional practical expedient which allows entities to exclude from evaluation land easements that exist or expired before adoption of ASU 2016-02. The Company is currently evaluating this practical expedient and will adopt ASU 2018-01 at the same time as ASU 2016-02.

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 has determined that the adoption of ASU 2017-01 on the effective date of January 1, 2018, using a prospective method, does not impact the Company's current consolidated financial statements or disclosures. However, the clarified definition of a business will be applied by the Company to future transactions.

In February 2017, the FASB issued ASU No. 2017-05, Other Income-Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets ("ASU 2017-05"). ASU 2017-05 is meant to clarify the scope of Accounting Standards Codification ("ASC") Subtopic 610-20, Other Income-Gains and Losses from the Derecognition of Nonfinancial Assets and to add guidance for partial sales of nonfinancial assets. The Company has determined that the adoption of ASU 2017-05 on the effective date of January 1, 2018, using a modified retrospective method, does not impact the Company's current consolidated financial statements or disclosures.

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

In February 2018, the FASB issued ASU No. 2018-02, Income Statement–Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income ("ASU 2018-02"). ASU 2018-02 permits entities to reclassify tax effects stranded in accumulated other comprehensive income (loss) to retained earnings as a result of the 2017 Tax Act. ASU 2018-02, is to be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the United States federal corporate income tax rate in the 2017 Tax Act is recognized. The guidance is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2018. Early adoption is permitted as outlined in ASU 2018-02. The Company is currently evaluating the provisions of this guidance and assessing the potential impact on the Company's consolidated financial statements and disclosures.

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, 2017, and through the filing of this report.

Note 2 – Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following accruals:

	As of December 31,	
	2017	2016
	(in thousands)	
Oil, gas, and NGL production revenue	$96,610	$96,101
Amounts due from joint interest owners	56,929	29,669
State severance tax refunds	2,276	15,320
Derivative settlements	99	6,512
Other	4,240	4,348
Total accounts receivable	$160,154	$151,950

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

	As of December 31,	
	2017	2016
	(in thousands)	
Capital expenditures	$164,620	$107,009
Revenue and severance tax payable	60,328	39,617
Lease operating expense	22,078	15,956
Property taxes	13,222	6,606
Compensation	39,471	34,761
Derivative settlements	12,644	6,473
Interest	45,057	45,059
Other	29,210	44,227
Total accounts payable and accrued expenses	$386,630	$299,708

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

2017 Divestiture Activity

Eagle Ford Divestiture. During the first quarter of 2017, the Company divested its outside-operated Eagle Ford shale assets, including its ownership interest in related midstream assets, for total cash received, net of costs (referred to throughout this report as "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. These assets were classified as held for sale as of December 31, 2016.

The following table presents income (loss) before income taxes from the outside-operated Eagle Ford shale assets sold for the years ended December 31, 2017, 2016, and 2015. This divestiture was considered a disposal of a significant asset group.

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Income (loss) before income taxes (1)	$24,324	$(218,506)	$71,556

(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 approximately $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 a small net gain. Please refer to the Assets Held for Sale section below for an explanation of divestiture losses the Company recorded during 2017 for its Divide County, North Dakota assets, which were held for sale in the first quarter and a portion of the second quarter of 2017.

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 packages for 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 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.

2015 Divestiture Activity

Mid-Continent Divestiture. During the second quarter of 2015, the Company divested its Mid-Continent assets in multiple transactions for total net divestiture proceeds of $310.3 million and a final net gain of $108.4 million. In conjunction with the divestiture of its Mid-Continent assets, the Company closed its Tulsa, Oklahoma office.

Permian Divestiture. During the fourth quarter of 2015, the Company divested certain non-core assets in its Permian region. Net divestiture proceeds were $25.1 million and the final net gain on this divestiture was $2.3 million. Write-downs on certain other assets held for sale and subsequently sold during the year ended December 31, 2015, totaled $68.6 million, which partially offset the net gain on the Mid-Continent and Permian divestitures discussed above.

Assets 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 in the accompanying statements of operations.

During the year ended December 31, 2017, the Company recorded a $526.5 million write-down on its retained Divide County, North Dakota assets held for sale in early 2017, of which $359.6 million was recorded in the first quarter of 2017 based on estimated fair value less selling costs. An additional $166.9 million write-down was recorded in the second quarter of 2017 based on market conditions that existed on the date the Company decided to retain the assets.
As of December 31, 2017, the accompanying balance sheets present $111.7 million of assets held for sale, net of accumulated depletion, depreciation, and amortization expense, which consists primarily of approximately 112,000 net acres in the Powder River Basin. A corresponding aggregate asset retirement obligation liability of $11.4 million is separately presented. Subsequent to December 31, 2017, the Company entered into a definitive agreement for the sale of these assets for a gross purchase price of $500.0 million, subject to customary closing price adjustments. The Company expects to close this divestiture in the first quarter of 2018. The closing of this divestiture is subject to the satisfaction of customary closing conditions and there can be no assurance that the transaction will close on time or at all.

The Company determined that neither planned nor executed asset sales qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

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 and the Senior Convertible Notes and equity offerings in August 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. Refer to Note 11 – Fair Value Measurements for additional discussion on the valuation techniques used in determining the fair value of the acquired properties. 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

(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.

2015 Acquisition Activity
There was no significant acquisition activity during the year ended December 31, 2015.

Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Current portion of income tax expense			
Federal	$5,698	$2,932	$—
State	3,398	1,539	1,571
Deferred portion of income tax benefit	(192,066)	(448,643)	(276,722)
Total income tax benefit	$(182,970)	$(444,172)	$(275,151)
Effective tax rate	53.2 %	37.0 %	38.1 %

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

	As of December 31,	
	2017	2016
	(in thousands)	
Deferred tax liabilities		
Oil and gas properties	$142,467	$518,394
Other	3,412	7,733
Total deferred tax liabilities	145,879	526,127
Deferred tax assets		
Derivative liabilities	29,463	31,349
Credit carryover	22,537	12,448
Pension	7,986	10,366
Federal and state tax net operating loss carryovers	3,867	151,343
Stock compensation	3,545	10,083
Other liabilities	1,470	201
Total deferred tax assets	68,868	215,790
Valuation allowance	(2,978)	(5,335)
Net deferred tax assets	65,890	210,455
Total net deferred tax liabilities	$79,989	$315,672
Current federal income tax refundable	$37	$644
Current state income tax payable	$3,009	$1,181

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. This rate change was required to be applied to the Company's total temporary differences as of December 31, 2017, resulting in a decrease in net deferred tax liabilities and a realized tax benefit of $63.7 million in the fourth quarter of 2017. This realized tax benefit amount represents 18.5 percentage points of the effective tax rate for 2017 reported above. Please refer to the table below for additional detail. Although the Company believes it has properly analyzed the tax accounting impacts of the 2017 Tax Act and appropriately re-measured its net deferred tax liability as of December 31, 2017, it will continue to monitor provisions with discrete rate impacts, such as the limitation on executive compensation, for subsequent events and guidance within one year of the enacted date.

As of December 31, 2017, the Company estimated its federal net operating loss ("NOL") carryforward at $1.3 million, which reflects the planning strategies to utilize NOLs for the 2017 and 2016 tax years. 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 R&D credit carryforwards of $7.2 million. The federal R&D credit carryforwards expire between 2028 and 2033. The Company's AMT credit carryforward of $15.7 million does not expire and is expected to be fully refunded by 2022 subject to possible limitations placed on these types of refunds under the sequestration rules enacted by Congress. State NOL carryforwards were $71.8 million and state tax credits were $283,000 as of December 31, 2017. Federal and state NOLs and state credits expire between 2018 and 2038. The Company's current valuation allowance relates to state NOL carryforwards and state tax credits, which could not be utilized in the respective states for the tax years 2017 and 2016, and are expected to expire before they can be utilized. The change in the valuation allowance from 2016 to 2017 primarily relates to an allocable change to the Company's mix of state apportioned losses, anticipated utilization of state cumulative NOLs and to a lesser extent the cumulative state effect of adopting ASU 2016-09.
Federal income tax benefit differs from the amount that would be provided by applying the U.S. federal statutory rate to income before income taxes primarily due to the effect of state income taxes, changes in valuation allowances, R&D credits, and accumulated impacts of other smaller permanent differences, reported as follows:

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Federal statutory tax benefit	$(120,335)	$(420,671)	$(253,001)
Increase (decrease) in tax resulting from:			
Federal tax reform changes - 2017 Tax Act	(63,675)	—	—
State tax benefit (net of federal benefit)	(3,286)	(17,549)	(21,583)
Change in valuation allowance	(2,727)	(5,059)	3,148
Employee share-based compensation	8,190	—	—
Other	(1,137)	(893)	(3,715)
Income tax benefit	$(182,970)	$(444,172)	$(275,151)

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.
The Company and its subsidiaries file federal income tax returns and various state income tax returns. With an exception for activity related to its 2003 - 2005 tax years, the Company is generally no longer subject to United States federal or state income tax examinations by tax authorities for years before 2013. The exception tax years have been reopened for net operating loss carryback claims and are currently under examination by the Internal Revenue Service (the "IRS"). During the third quarter of 2017, the Company received a $5.5 million refund in advance of the IRS completing its examination of the Company's claims. During 2016, the Company's 2007 - 2011 IRS examination was finalized, as was the 2013 IRS audit of the SM-Mitsui Tax Partnership with no material adjustments to previously recorded amounts. The Company recorded an additional $2.0 million net R&D credit in 2015 as a result of its R&D credit settlement with the IRS Appeals Office.
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 2018.

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

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Beginning balance	$446	$2,782	$1,582
Additions for tax positions of prior years	—	9	1,200
Settlements	—	(2,345)	—
Ending balance	$446	$446	$2,782

Note 5 – Long-Term Debt

Credit Agreement

The Company's Credit Agreement provides for a maximum loan amount of $2.5 billion and has a maturity date of December 10, 2019. On March 31, 2017, the Company entered into the Ninth Amendment with its lenders. Pursuant to the Ninth Amendment, and as part of the regular, semi-annual borrowing base redetermination process, the borrowing base and aggregate lender commitments were reduced to $925 million primarily due to the sale of the Company's outside-operated Eagle Ford shale assets and the decrease in the value of the Company's estimated proved reserves as of December 31, 2016.

The borrowing base redetermination process considers the value of both the Company's (a) proved oil and gas properties reflected in the Company's most recent reserve report and (b) commodity derivative contracts, each as determined by the Company's lender group. The next semi-annual redetermination date is scheduled for April 1, 2018.

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. Financial covenants under the Credit Agreement require, as of the last day of each of the Company's fiscal quarters, the Company's (a) ratio of senior secured debt to 12-month trailing adjusted EBITDAX to be not more than 2.75 to 1.0; (b) adjusted current ratio to be not less than 1.0 to 1.0; and (c) ratio of 12-month trailing adjusted EBITDAX to interest expense to be not less than 2.0 to 1.0. The Company was in compliance with all financial and non-financial covenants under the Credit Agreement as of December 31, 2017, 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 table below, and Alternate Base Rate ("ABR") and swingline loans accrue interest at the prime rate, plus the applicable margin from the utilization table below. Commitment fees are accrued on the unused portion of the aggregate lender commitment amount and are included in interest expense in the accompanying statements of operations. The borrowing base utilization grid under the Credit Agreement is as follows:

Borrowing Base Utilization Percentage	<25%	≥25% <50%	≥50% <75%	≥75% <90%	≥90%
Eurodollar Loans	1.750%	2.000%	2.250%	2.500%	2.750%
ABR Loans or Swingline Loans	0.750%	1.000%	1.250%	1.500%	1.750%
Commitment Fee Rate	0.300%	0.300%	0.350%	0.375%	0.375%

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 14, 2018, December 31, 2017, and December 31, 2016:

	As of February 14, 2018	As of December 31, 2017	As of December 31, 2016
	(in thousands)		
Credit facility balance (1)	$—	$—	$—
Letters of credit (2)	200	200	200
Available borrowing capacity	924,800	924,800	1,164,800
Total aggregate lender commitment amount	$925,000	$925,000	$1,165,000

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(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 $3.1 million and $5.9 million as of December 31, 2017, and 2016, respectively.

(2) Letters of credit outstanding reduce the amount available under the credit facility on a dollar-for-dollar basis.

Senior Notes

The Company's Senior Notes consist of 6.50% Senior Notes due 2021, 6.125% Senior Notes due 2022, 6.50% Senior Notes due 2023, 5.0% Senior Notes due 2024, 5.625% Senior Notes due 2025, and 6.75% Senior Notes due 2026 (collectively referred to as "Senior Notes"). The Senior Notes, net of unamortized deferred financing costs line on the accompanying balance sheets as of December 31, 2017, and 2016, consisted of the following:

	As of December 31,					
	2017			2016		
	Principal Amount	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs	Principal Amount	Unamortized Deferred Financing Costs	Senior Notes, Net of Unamortized Deferred Financing Costs
	(in thousands)					
6.50% Senior Notes due 2021	$344,611	$ 2,656	$ 341,955	$346,955	$ 3,372	$ 343,583
6.125% Senior Notes due 2022	561,796	5,800	555,996	561,796	6,979	554,817
6.50% Senior Notes due 2023	394,985	3,707	391,278	394,985	4,436	390,549
5.0% Senior Notes due 2024	500,000	5,610	494,390	500,000	6,533	493,467
5.625% Senior Notes due 2025	500,000	6,714	493,286	500,000	7,619	492,381
6.75% Senior Notes due 2026	500,000	7,242	492,758	500,000	8,078	491,922
Total	$2,801,392	$ 31,729	$ 2,769,663	$2,803,736	$ 37,017	$ 2,766,719

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; however, the first $6.5 million of dividends paid each year are not restricted by the restricted payment covenant. The Company was in compliance with all covenants under its Senior Notes as of December 31, 2017, 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 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.
2019 Notes. During 2015, the Company conducted a tender offer and subsequent redemption of its 2019 Notes. As a result, the Company recorded a loss on the extinguishment of debt of approximately $16.6 million for the year ended December 31, 2015. This amount includes approximately $12.5 million associated with the premium paid for the tender offer and redemption of the 2019 Notes and approximately $4.1 million related to the acceleration of unamortized deferred financing costs.
2021 Notes. On November 8, 2011, the Company issued $350.0 million in aggregate principal amount of 6.50% Senior Notes due 2021 at par, which mature on November 15, 2021. The Company received net proceeds of $343.1 million after deducting fees of $6.9 million, which are being amortized as deferred financing costs over the life of the 2021 Notes. During the first quarter of 2016, the Company repurchased $3.1 million in aggregate principal amount of its 2021 Notes for a settlement amount of $2.3 million, excluding interest. During the first quarter of 2017, the Company repurchased in open market transactions a total of $2.3 million in aggregate principal amount of its 2021 Notes at a slight premium.
2022 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.
2023 Notes. On June 29, 2012, the Company issued $400.0 million in aggregate principal amount of 6.50% Senior Notes due 2023 at par, which mature on January 1, 2023. The Company received net proceeds of $392.1 million after deducting fees of $7.9 million, which are being amortized as deferred financing costs over the life of the 2023 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, excluding interest.
2024 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 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. The net proceeds were used to fund the consideration paid to the tendering holders of the 2019 Notes and to redeem the remaining untendered 2019 Notes, as well as repay outstanding borrowings under the Credit Agreement and for general corporate purposes.
2026 Notes. On September 12, 2016, the Company issued $500.0 million in aggregate principal amount of 6.75% Senior Notes due 2026, at par (the “2026 Notes”), 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.
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 (the “Senior Convertible Notes”). 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.
The Senior Convertible Notes mature on July 1, 2021, unless earlier converted. 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

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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, 2017, 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, 2017, 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 $9.9 million and $3.7 million for the years ended December 31, 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, 2017 and 2016:

	As of December 31,	
	2017	2016
	(in thousands)	
Principal amount of Senior Convertible Notes	$172,500	$172,500
Unamortized debt discount	(30,183)	(37,513)
Unamortized deferred financing costs	(3,210)	(4,131)
Net carrying amount	$139,107	$130,856

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, 2017 and 2016:

	As of December 31,	
	2017	2016
	(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, 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, 2017, 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, 2017, 2016, and 2015, were $12.6 million, $17.0 million, and $25.1 million, respectively.

Note 6 – Commitments and Contingencies

Commitments

The Company has entered into various agreements, which include drilling rig contracts of $37.8 million, gathering, processing, transportation throughput, and delivery commitments of $463.4 million, office leases, including maintenance, of $43.3 million, and other miscellaneous contracts and leases of $30.2 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)
2018	$ 113,774
2019	112,860
2020	111,107
2021	102,606
2022	72,073
Thereafter	62,245
Total	$ 574,665

Subsequent to December 31, 2017, the Company entered into a fixed price contract to purchase electricity through 2027 for a total of $27.9 million. As of the filing of this report, the Company expects to meet this purchase commitment.

Drilling Contracts

The Company has several drilling rig contracts in place to facilitate drilling plans. Early termination of these rig contracts as of December 31, 2017, would have resulted in termination penalties of $27.7 million, which would be in lieu of paying the remaining drilling commitments of $37.8 million included in the table above. For the years ended December 31, 2016, and 2015, the Company incurred $8.7 million and $13.7 million, respectively, 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 such expenses were recorded by the Company for the year ended December 31, 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, 2017, the Company has commitments to deliver a minimum of 19 MMBbl of oil, 789 Bcf of gas, and 24 MMBbl of produced water through 2028. 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, 2017, if the Company fails to deliver any product, as applicable, the aggregate undiscounted deficiency payments total approximately $463.4 million. If a shortfall in the minimum volume commitment for gas is projected, the Company has rights under certain contracts to arrange for third-party gas to be delivered, and such volumes would count toward its minimum volume commitment.

During the first quarter of 2017, the Company completed the divestiture of its outside-operated Eagle Ford shale assets. Upon closing of the sale, the Company is no longer subject to transportation throughput commitments totaling 52 MMBbl of oil, 514 Bcf of gas, and 13 MMBbl of NGLs, or $501.9 million of the potential undiscounted deficiency payments as of December 31, 2016.

As of the filing of this report, the Company does not expect to incur any material shortfalls.

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, 2017, 2016, and 2015, was $4.8 million, $5.2 million, and $6.1 million, respectively. The Company closed its office in Billings, Montana in November 2016 and paid $3.2 million to the lessor to terminate the lease, which is not reflected in the rent expense amount 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 results of such pending litigation and claims is not likely 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 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, 2017, approximately 3.3 million shares of common stock remained 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 long-term equity compensation program. 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 measurement period. The performance criteria for PSUs are based on a combination of the Company's annualized Total Shareholder Return ("TSR") for the performance period and the relative performance of the Company's TSR compared with the annualized TSR of certain peer companies for the performance period. Compensation expense for PSUs is recognized within general and administrative and exploration expense over the vesting periods of the respective awards.

The fair value of PSUs is measured at the grant date with a stochastic process method using the Geometric Brownian Motion Model ("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.

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 $9.7 million, $11.0 million, and $10.6 million for the years ended December 31, 2017, 2016, and 2015, respectively. As of December 31, 2017, there was $18.8 million of total unrecognized expense related to PSUs, which is being amortized through 2020.

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

	For the Years Ended December 31,					
	2017		2016		2015	
	PSUs	Weighted-Average Grant-Date Fair Value	PSUs	Weighted-Average Grant-Date Fair Value	PSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year [1]	828,923	$ 43.25	626,328	$ 61.81	433,660	$ 73.63
Granted [1]	977,731	$ 15.86	447,971	$ 26.56	320,753	$ 45.34
Vested [1]	(94,338)	$ 85.85	(130,353)	$ 64.17	(76,438)	$ 51.76
Forfeited [1]	(178,825)	$ 44.99	(115,023)	$ 55.59	(51,647)	$ 73.62
Non-vested at end of year[1]	1,533,491	$ 22.97	828,923	$ 43.25	626,328	$ 61.81

(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 2017, 2016, and 2015 was $15.5 million, $11.9 million, and $14.5 million, respectively. The PSUs granted in 2015 will remain non-vested until the third anniversary date of their issuance, at which time they will fully vest, unless the employee is retirement eligible in which case the PSUs vest immediately upon attainment of retirement age. PSUs granted in 2017 and 2016 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, 2017, there were no shares of common stock issued to settle PSUs granted in 2014 as the multiplier earned was zero. A summary of the shares of common stock issued to settle PSUs for the years ended December 31, 2016, and 2015, is presented in the table below:

	For the Years Ended December 31,	
	2016	2015
Shares of common stock issued to settle PSUs [1]	44,870	288,962
Less: shares of common stock withheld for income and payroll taxes	(14,809)	(100,683)
Net shares of common stock issued	30,061	188,279
Multiplier earned	0.2	1.0

(1) During the years ended December 31, 2016, and 2015, the Company issued shares of common stock for PSUs granted in 2013, and 2012. 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, 2017, 2016, and 2015 was $8.1 million, $8.4 million, and $4.0 million, respectively.

Employee Restricted Stock Units

The Company grants RSUs to eligible employees as part of its long-term equity incentive compensation program. 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 award.

Total compensation expense recorded for employee RSUs for the years ended December 31, 2017, 2016, and 2015, was $10.3 million, $11.9 million, and $13.4 million, respectively. As of December 31, 2017, there was $19.3 million of total unrecognized expense related to non-vested RSU awards, which is being amortized through 2020. 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 for eligible employees is presented in the following table:

	For the Years Ended December 31,					
	2017		2016		2015	
	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	604,116	$ 37.39	543,737	$ 55.01	515,724	$ 68.29
Granted	1,020,780	$ 16.64	417,065	$ 28.08	356,246	$ 43.72
Vested	(246,025)	$ 43.99	(241,363)	$ 58.06	(278,289)	$ 63.12
Forfeited	(134,609)	$ 26.38	(115,323)	$ 43.52	(49,944)	$ 66.53
Non-vested at end of year	1,244,262	$ 20.25	604,116	$ 37.39	543,737	$ 55.01

The fair value of RSUs granted to eligible employees in 2017, 2016, and 2015 was $17.0 million, $11.7 million, and $15.6 million, respectively. The RSUs granted in 2015 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 vest immediately upon attainment of retirement age. The RSUs granted in 2017 and 2016 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 a 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,		
	2017	2016	2015
Shares of common stock issued to settle RSUs (1)	246,025	241,363	278,289
Less: shares of common stock withheld for income and payroll taxes	(74,747)	(72,181)	(91,045)
Net shares of common stock issued	171,278	169,182	187,244

(1) During the years ended December 31, 2017, 2016, and 2015, the Company issued shares of common stock for RSUs 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, 2017, 2016, and 2015 was $10.8 million, $14.0 million, and $17.6 million, respectively.

Director Shares and Restricted Stock Units

In 2017, 2016, and 2015, the Company issued 71,573, 53,473, and 39,903 shares, respectively, of its common stock to its non-employee directors under the Company's Equity Plan. Also in 2017, the Company issued 8,794 RSUs to a non-employee director. For the years ended December 31, 2017, 2016, and 2015, the Company recorded $1.6 million, $2.0 million, and $1.6 million, respectively, of compensation expense related to director shares and RSUs issued. Beginning with the awards granted in 2016, all shares issued to non-employee directors fully vest on December 31st of the year granted. Prior to 2016, all shares of common stock issued to the Company's non-employee directors were earned over the one-year service period following the date of grant, unless five years of service had been provided to the Company by the director, in which case that director's shares vested upon the earlier of the completion of the one year service period or the director retiring from the Board of Directors. 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 IRC. The Company had approximately 1.8 million shares of its common stock available for issuance under the ESPP as of December 31, 2017. There were 186,665, 218,135, and 197,214 shares issued under the ESPP in 2017, 2016, and 2015, respectively. Total proceeds to the Company for the issuance of these shares were $2.6 million, $4.2 million, and $4.8 million for the years ended December 31, 2017, 2016, and 2015, respectively.

The fair value of ESPP grants is measured at the date of grant using the Black-Scholes-Merton 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,		
	2017	2016	2015
Risk free interest rate	0.9 %	0.4 %	0.1 %
Dividend yield	0.5 %	0.4 %	0.2 %
Volatility factor of the expected market price of the Company's common stock	62.5%	95.0%	61.2%
Expected life (in years)	0.5	0.5	0.5

The Company expensed $1.0 million, $2.0 million, and $1.8 million for the years ended December 31, 2017, 2016, and 2015, 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 each employee's contribution up to six percent of the employee's base salary and performance bonus, and may make additional contributions at its discretion. The Company matches contributions made by employees hired after December 31, 2014, up to nine 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 $4.5 million, $5.4 million, and $5.6 million for the years ended December 31, 2017, 2016, and 2015, 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 on divestiture activity line item in the accompanying statements of operations.

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Cash payments made or accrued related to operations	$(54)	$6,608	$3,498
Cash payments made or accrued related to divestitures	2,753	24,349	3,789
Total net settlements	$2,699	$30,957	$7,287

Note 8 – Pension Benefits

The Company has a non-contributory defined benefit pension plan covering substantially all 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 as of December 31, 2014, 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 accumulated other comprehensive income (loss), net of tax. 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,	
	2017	2016
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$69,659	$62,547
Service cost	6,638	8,200
Interest cost	2,689	2,908
Actuarial loss	3,708	2,662
Benefits paid	(10,757)	(6,658)
Projected benefit obligation at end of year	71,937	69,659
Change in plan assets:		
Fair value of plan assets at beginning of year	31,731	25,769
Actual return on plan assets	2,956	1,575
Employer contribution	7,048	11,045
Benefits paid	(10,757)	(6,658)
Fair value of plan assets at end of year	30,978	31,731
Funded status at end of year	$(40,959)	$(37,928)

The Company’s underfunded status for the Pension Plans as of December 31, 2017, and 2016, was $41.0 million and $37.9 million, respectively, and is recognized in the accompanying balance sheets as a portion of other noncurrent liabilities. No plan assets of the Qualified Pension Plan were returned to the Company during the year ended December 31, 2017. 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,	
	2017	2016
	(in thousands)	
Projected benefit obligation	$71,937	$69,659
Accumulated benefit obligation	$56,045	$54,681
Less: Fair value of plan assets	(30,978)	(31,731)
Underfunded accumulated benefit obligation	$25,067	$22,950

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 a 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, 2017, and 2016, were as follows:

	As of December 31,	
	2017	2016
	(in thousands)	
Unrecognized actuarial losses	$21,397	$22,708
Unrecognized prior service costs	66	83
Accumulated other comprehensive loss	$21,463	$22,791

The estimated net loss that will be amortized from accumulated other comprehensive loss into net periodic benefit cost for the year ended December 31, 2018, is $1.3 million.

The pension liability adjustments recognized in other comprehensive income (loss) during 2017, 2016, and 2015, were as follows:

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Net actuarial loss	$(2,995)	$(3,322)	$(4,990)
Amortization of prior service cost	17	16	17
Amortization of net actuarial loss	1,297	1,582	1,486
Settlements	3,009	—	350
Total pension liability adjustment, pre-tax	1,328	(1,724)	(3,137)
Tax (expense) benefit	(561)	570	1,047
Total pension liability adjustment, net of tax	$767	$(1,154)	$(2,090)

Components of Net Periodic Benefit Cost for the Pension Plans

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Components of net periodic benefit cost:			
Service cost	$6,638	$8,200	$7,949
Interest cost	2,689	2,908	2,496
Expected return on plan assets that reduces periodic pension benefit cost	(2,244)	(2,235)	(2,182)
Amortization of prior service cost	17	16	17
Amortization of net actuarial loss	1,297	1,582	1,486
Settlements	3,009	—	350
Net periodic benefit cost	$11,406	$10,471	$10,116

Pension Plan Assumptions

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

	As of December 31,	
	2017	2016
Projected benefit obligation:		
Discount rate	3.8%	4.2%
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,		
	2017	2016	2015
Net periodic benefit cost:			
Discount rate	4.2%	4.7%	4.3%
Expected return on plan assets (1)	6.5%	7.5%	7.5%
Rate of compensation increase	6.2%	6.2%	6.2%

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(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	2018	2017	2016
Equity securities	35.0 %	38.4 %	28.8 %
Fixed income securities	43.0 %	39.8 %	35.5 %
Other securities	22.0 %	21.8 %	35.7 %
Total	100.0%	100.0%	100.0%

There is no asset allocation of the Nonqualified Pension Plan since there are no plan assets in that plan. An expected return on plan assets of 6.5 percent and 7.5 percent was used to calculate the Company's obligation under the Qualified Pension Plan as of December 31, 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.

Pension Plan Assets

The fair values of the Company's Qualified Pension Plan assets as of December 31, 2017, and 2016, 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, 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 corp 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
As of December 31, 2016						
Cash	—	%	$—	$—	$—	$—
Equity securities:						
Domestic (2)	18.7	%	5,945	4,471	1,474	—
International (3)	10.1	%	3,192	3,192	—	—
Total equity securities	28.8	%	9,137	7,663	1,474	—
Fixed income securities:						
High-yield bonds (4)	2.6	%	822	822	—	—
Core fixed income (5)	25.0	%	7,923	7,923	—	—
Floating rate corp loans (6)	7.9	%	2,495	2,495	—	—
Total fixed income securities	35.5	%	11,240	11,240	—	—
Other securities:						
Commodities (7)	1.8	%	578	578	—	—
Real estate (8)	5.1	%	1,629	—	—	1,629
Collective investment trusts (9)	17.5	%	5,562	—	5,562	—
Hedge fund (10)	11.3	%	3,585	—	—	3,585
Total other securities	35.7	%	11,354	578	5,562	5,214
Total investments	100.0	%	$31,731	$19,481	$7,036	$5,214

(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 this fund 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 an investment in an actively traded global mutual fund that focuses 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, 2016	$5,045
Purchases	561
Realized gain on assets	54
Unrealized gain on assets	115
Disposition	(561)
Balance at December 31, 2016	$5,214
Purchases	300
Realized gain on assets	130
Unrealized gain on assets	120
Disposition	(555)
Balance at December 31, 2017	$5,209

Contributions

The Company contributed $7.0 million, $11.0 million, and $6.4 million to the Pension Plans in the years ended December 31, 2017, 2016, and 2015, respectively. The Company expects to make a $4.0 million contribution to the Pension Plans in 2018.

Benefit Payments

The Pension Plans made actual benefit payments of $10.8 million, $6.7 million, and $8.2 million in the years ended December 31, 2017, 2016, and 2015, respectively. Expected benefit payments over the next 10 years are as follows:

Years Ending December 31,	(in thousands)
2018	$ 4,217
2019	$ 3,818
2020	$ 4,363
2021	$ 5,561
2022	$ 6,117
2023 through 2027	$ 36,279

Note 9 – 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,	
	2017	2016
	(in thousands)	
Beginning asset retirement obligations	$123,307	$140,874
Liabilities incurred [1]	7,588	21,293
Liabilities settled [2]	(30,432)	(57,100)
Accretion expense	5,988	7,795
Revision to estimated cash flows	8,019	10,445
Ending asset retirement obligations [3][4]	$114,470	$123,307

(1) Reflects liabilities incurred through drilling activities and acquisitions of drilled wells.

(2) Reflects liabilities settled through plugging and abandonment activities and divestitures of properties.

(3) Balances as of December 31, 2017, and 2016, included $11.4 million and $26.2 million, respectively, of asset retirement obligations associated with oil and gas properties held for sale.

(4) Balances as of December 31, 2017, and 2016, included $75,000 and $932,000, respectively, related to the Company’s current asset retirement obligation liability, which is recorded in accounts payable and accrued expenses on the accompanying balance sheets.

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, 2017, all derivative counterparties were members of the Company’s credit facility 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 swap arrangements for gas and NGLs. 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.

As of December 31, 2017, the Company had commodity derivative contracts outstanding through the second quarter of 2020, as summarized in the tables below.

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(MBbl)	(per Bbl)
First quarter 2018	1,075	$ 50.16
Second quarter 2018	1,534	$ 49.57
Third quarter 2018	1,769	$ 49.77
Fourth quarter 2018	1,894	$ 49.87
2019	1,940	$ 50.70
Total	8,212	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MBbl)	(per Bbl)	(per Bbl)
First quarter 2018	1,445	$ 50.00	$ 59.07
Second quarter 2018	1,459	$ 50.00	$ 59.03
Third quarter 2018	1,948	$ 50.00	$ 58.61
Fourth quarter 2018	2,222	$ 50.00	$ 58.44
2019	5,908	$ 47.65	$ 59.19
Total	12,982		

Oil Basis Swaps

Contract Period	Midland-Cushing Volumes	Weighted-Average Contract Price[(1)]
	(MBbl)	(per Bbl)
First quarter 2018	2,113	$ (1.15)
Second quarter 2018	2,392	$ (1.03)
Third quarter 2018	3,018	$ (1.06)
Fourth quarter 2018	3,327	$ (1.08)
2019	5,788	$ (1.09)
Total	16,638	

(1) Represents the price differential between WTI prices at Midland, Texas and WTI prices at Cushing, Oklahoma.

Gas Swaps

Contract Period	Sold Volumes	Weighted-Average Contract Price	Purchased Volumes	Weighted-Average Contract Price	Net Volumes
	(BBtu)	(per MMBtu)	(BBtu)	(per MMBtu)	(BBtu)
First quarter 2018	28,910	$ 3.55	(8,121)	$ 4.34	20,789
Second quarter 2018	23,507	$ 3.31	(7,795)	$ 4.24	15,712
Third quarter 2018	24,627	$ 3.29	(7,480)	$ 4.23	17,147
Fourth quarter 2018	25,856	$ 3.29	(7,210)	$ 4.27	18,646
2019	41,394	$ 3.76	(24,415)	$ 4.34	16,979
Total [(1)]	144,294		(55,021)		89,273

(1) Total net volumes of gas swaps are comprised of IF HSC (99%) and IF El Paso Permian (1%).

NGL Swaps

	OPIS Purity Ethane 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	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price	Volumes	Weighted-Average Contract Price
	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)	(MBbl)	(per Bbl)
First quarter 2018	923	$ 10.90	629	$ 24.39	206	$ 35.83	167	$ 35.76	188	$ 49.40
Second quarter 2018	915	$ 10.87	554	$ 24.94	84	$ 35.69	66	$ 35.07	109	$ 49.57
Third quarter 2018	1,033	$ 10.99	610	$ 24.27	93	$ 35.70	70	$ 35.07	118	$ 49.56
Fourth quarter 2018	1,146	$ 11.18	671	$ 24.39	102	$ 35.70	76	$ 35.07	129	$ 49.57
2019	3,533	$ 12.31	1,503	$ 27.83	154	$ 35.64	117	$ 35.70	197	$ 50.93
2020	539	$ 11.13	—	$ —	—	$ —	—	$ —	—	$ —
Total	8,089		3,967		639		496		741	

Commodity Derivative Contracts Entered Into After December 31, 2017

Subsequent to December 31, 2017, the Company entered into NGL Swap contracts for 2018 for approximately 228 MBbl of OPIS Natural Gasoline Mont Belvieu Non-TET NGL production at a contract price of $53.34 per Bbl.

Derivative Assets and Liabilities Fair Value

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The Company does not designate its derivative commodity contracts as hedging instruments. The fair value of the derivative commodity contracts was a net liability of $139.4 million at December 31, 2017, and net liability of $91.7 million at December 31, 2016.

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

	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

	As of December 31, 2016			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$54,521	Current liabilities	$115,464
Commodity contracts	Noncurrent assets	67,575	Noncurrent liabilities	98,340
Total commodity contracts		$122,096		$213,804

Offsetting of Derivative Assets and Liabilities

As of December 31, 2017, and 2016, 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		Derivative Liabilities	
	As of December 31,		As of December 31,	
Offsetting of Derivative Assets and Liabilities	2017	2016	2017	2016
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$104,628	$122,096	$(243,984)	$(213,804)
Amounts not offset in the accompanying balance sheets	(100,035)	(118,080)	100,035	118,080
Net amounts	$4,593	$4,016	$(143,949)	$(95,724)

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, 2017, 2016, and 2015. 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 net derivative (gain) loss presented in the accompanying statements of operations:

	For the Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Derivative settlement (gain) loss:			
Oil contracts	$31,176	$(243,102)	$(362,219)
Gas contracts [1]	(87,857)	(94,936)	(123,180)
NGL contracts	35,447	8,560	(27,167)
Total derivative settlement gain	$(21,234)	$(329,478)	$(512,566)
Net derivative (gain) loss:			
Oil contracts	$71,502	$85,370	$(191,165)
Gas contracts	(76,315)	81,060	(189,734)
NGL contracts	31,227	84,203	(27,932)
Total net derivative (gain) loss	$26,414	$250,633	$(408,831)

(1) Gas derivative settlements for the year ended December 31, 2015, include $15.3 million of early settlements of futures contracts as a result of divesting assets in the Company's Mid-Continent region.

Credit Related Contingent Features

As of December 31, 2017, and through the filing of this report, all of the Company's derivative counterparties were members of the Company's credit facility lender group. The Company's obligations under its Credit Agreement and derivative contracts are secured by mortgages on assets having a value equal to at least 90 percent of the total PV-9 of the Company's proved oil and gas properties evaluated in the most recent reserve report.

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

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	$ —

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[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, 2016:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives [1]	$—	$122,096	$—
Total property and equipment, net [2]	$—	$—	$88,205
Liabilities:			
Derivatives [1]	$—	$213,804	$—

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

[2] This represents a non-financial asset that is measured at fair value on a nonrecurring 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. All of the Company's commodity derivative counterparties are members of the Company's credit facility lender group.

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 with 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 commodity derivative instruments.

Proved and Unproved Oil and Gas Properties and Other Property and Equipment

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 the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future cash flow amounts to a single present value amount, 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. The calculation of the discount rates is based on the best information available and the rates used ranged from 10 percent to 15 percent based on the reservoir specific weightings of future estimated proved and unproved cash flows as of December 31, 2017, and 2016. The Company believes the discount rates are representative of current market conditions and consider 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 prices for oil and gas are forecast 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 forecast 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 Company did not recognize any material impairment of proved properties expense for the year ended 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 for 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. The Company recorded impairment of proved properties expense of $468.7 million for the year ended December 31, 2015, related primarily to the decline in expected reserve cash flows driven by commodity price declines recorded mainly in the Company's East Texas and Powder River Basin programs with smaller impacts on other legacy and non-core assets in the Rocky Mountain region.

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. 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.

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

	For the Years Ended December 31,		
	2017	2016	2015
	(in millions)		
Abandonment and impairment of unproved properties	$12.3	$80.4	$78.6

Abandonment and impairment of unproved properties expense recorded during the year ended December 31, 2017, related primarily to lease expirations. 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. During the year ended

December 31, 2015, abandonment and impairment expense resulted from lease expirations and acreage the Company no longer intended to develop in light of changes in drilling plans in response to the decline in commodity prices.

Other property and equipment. 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. During the year ended December 31, 2015, the Company recorded impairment of other property and equipment expense of $49.4 million on the Company's gathering system assets in its east Texas program. These assets were impaired in conjunction with the impairment of the associated proved and unproved properties, which the Company did not intend to develop and subsequently sold. There were no other property and equipment impairments in 2017 or 2016.

Oil and gas properties held for sale. Proved and unproved oil and gas properties classified as held for sale, including the 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 income valuation techniques discussed above. Any initial write-down and subsequent changes to the fair value less estimated cost to sell is included within the net gain (loss) on divestiture activity line item in the accompanying statements of operations.

There were no assets held for sale recorded at fair value as of December 31, 2017, or 2016, as the carrying values were below the estimated fair values less costs to sell. However, for the year ended December 31, 2017, the Company recorded a $526.5 million write-down on its Divide County, North Dakota assets which were held for sale in early 2017. Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions for additional discussion.

Acquisitions of proved and unproved properties. Assets acquired and liabilities assumed under transactions that meet the criteria of a business combination under ASC Topic 805, Business Combinations are recorded at fair value on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of: (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 judgments and estimates by the Company's management at the time of the valuation.

Assets acquired and liabilities assumed under transactions that do not meet the criteria of a business combination under ASC Topic 805, Business Combinations are accounted for as an asset acquisition and are recorded based on the fair value of the total consideration transferred on the acquisition date using the lowest observable inputs available. In connection with the QStar Acquisition, the Company issued approximately 13.4 million shares of common stock as a component of the total consideration transferred to the sellers on December 21, 2016. Fair value of the equity consideration transferred was based on the closing price of the Company's common stock on the date of acquisition, as adjusted using an option pricing model to account for the lack of marketability of the shares issued.

Please refer to Note 3 – Divestitures, Assets Held for Sale, and Acquisitions for additional discussion.

Long-Term Debt

The following table reflects the fair value of the Senior Notes and Senior Convertible Notes 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, 2017, or 2016, as they are 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,			
	2017		2016	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(in thousands)			
6.50% Senior Notes due 2021	$344,611	$351,682	$346,955	$354,546
6.125% Senior Notes due 2022	$561,796	$571,627	$561,796	$570,925
6.50% Senior Notes due 2023	$394,985	$403,434	$394,985	$403,134
5.0% Senior Notes due 2024	$500,000	$483,440	$500,000	$475,975
5.625% Senior Notes due 2025	$500,000	$494,355	$500,000	$485,000
6.75% Senior Notes due 2026	$500,000	$516,350	$500,000	$516,565
1.50% Senior Convertible Notes due 2021	$172,500	$168,291	$172,500	$202,189

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 2017, 2016, and 2015. 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,		
	2017	2016	2015
	(in thousands)		
Beginning balance	$19,846	$11,952	$43,589
Additions to capitalized exploratory well costs pending the determination of proved reserves	49,446	19,846	11,952
Divestitures	—	—	(809)
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(19,846)	(11,952)	(18,485)
Capitalized exploratory well costs charged to expense	—	—	(24,295)
Ending balance	$49,446	$19,846	$11,952

As of December 31, 2017, 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 2017.

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,		
	2017	2016	2015
	(in thousands)		
Development costs (1)	$675,523	$595,331	$1,234,114
Exploration costs	271,502	118,224	132,465
Acquisitions (2)			
Proved properties	1,602	201,672	10,040
Unproved properties (3)	91,420	2,458,667	18,382
Total, including asset retirement obligations (4)(5)	$1,040,047	$3,373,894	$1,395,001

(1) Includes facility costs of $43.8 million, $25.9 million, and $75.6 million for the years ended December 31, 2017, 2016, and 2015, 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 outside of acquisitions of proved and unproved properties totaling $12.8 million, $7.5 million, and $17.5 million for the years ended December 31, 2017, 2016, and 2015, respectively.

(4) Includes amounts relating to estimated asset retirement obligations of $13.6 million, $32.1 million, and $38.5 million for the years ended December 31, 2017, 2016, and 2015, respectively.

(5) Includes capitalized interest of $12.6 million, $17.0 million, and $25.1 million for the years ended December 31, 2017, 2016, and 2015, 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, 2017. 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,								
	2017 (1)			2016 (2)			2015 (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	104.9	1,111.1	105.7	145.3	1,264.0	115.4	169.7	1,466.5	133.5
Revisions of previous estimate	1.0	63.8	4.9	(36.0)	(249.8)	(18.6)	(46.2)	(369.6)	(40.6)
Discoveries and extensions									